BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 040007-GU

In the Matter of

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OST RECOVERY.
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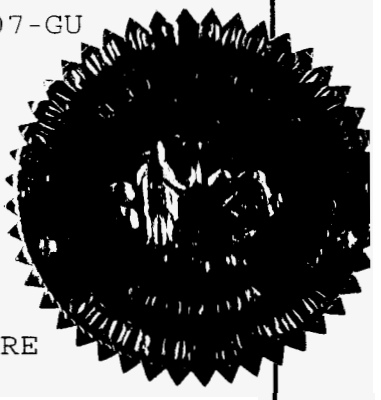

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| ROCEEDINGS: | HEARING |
| EFORE: | CHAIRMAN BRAULIO L. BAEZ<br>COMMISSIONER J. TERRY DEASON<br>RUDOLPH "RUDY" BRADLEY<br>COMMISSIONER CHARLES M. DAVIDSON |
| ATE: | Monday, November 8, 2004 |
| IME: | Commenced at 9:30 a.m. |
| LACE: | Betty Easley Conference Center<br>Room 148<br>4075 Esplanade Way<br>Tallahassee, Florida |
| EPORTED BY: | LINDA BOLES, RPR<br>Official FPSC Reporter<br>(850) 413-6734 |

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APPEARANCES:

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

JOHN T. BUTLER, Steel, Hector & Davis, LLP, 200 South Biscayne Boulevard, Suite 4000, Miami, Florida 33131-2398, appearing on behalf of Florida Power & Light Company.

VICKI GORDON KAUFMAN, ESQUIRE, and JOSEPH MCGLOTHLIN, ESQUIRE, McWhirter, Reeves Law Firm, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

GARY V. PERKO, ESQUIRE, Hopping, Green & Sams, P.A., Post Office Box 6526, Tallahassee, Florida 32314, appearing on behalf of Progress Energy Florida.

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

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P R O C E E D I N G S

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CHAIRMAN BAEZ: We'll take appearances. And I guess we should just take appearances on all the dockets together.

MS. FLEMING: Yes, Commissioner.

CHAIRMAN BAEZ: And we'll start on stage left and just move on down the line. If there's anybody that has to enter an appearance, they ought to move down quickly, if you're not -- if you haven't taken a seat already.

Go ahead, Mr. Butler.

MR. BUTLER: Thank you. Good morning, Commissioners. John Butler of the law firm Steel, Hector & Davis appearing on behalf of FPL in the 01 and 07 dockets. Also appearing on behalf of FPL in the 01 docket is Wade Litchfield and Natalie Futch Smith.

CHAIRMAN BAEZ: Thank you. Mr. Beasley.

MR. BEASLEY: Thank you, Mr. Chairman. James D. Beasley and Lee L. Willis with the law firm of Ausley & McMullen in Tallahassee. We're representing Tampa Electric Company in the 01, 02 and 07 dockets.

MR. McGEE: James McGee on behalf of Progress Energy Florida in the 01 and 02 dockets. Appearing with me is Bonnie Davis in the 01 docket.

MR. MOYLE: Jon Moyle, Jr., with the Moyle, Flanigan Law Firm on behalf of Mr. Tom Churbuck, and we are in the

040001 docket. I'd also like to enter an appearance, I'd like to do it on behalf of my law partner Bill Hollimon.

MR. PERKO: Gary Perko of the Hopping, Green & Sams Law Firm on behalf of City Gas Company of Florida in the 03 and 04 dockets, and Progress Energy Florida in the 07 docket.

MS. CHRISTENSEN: Patty Christensen on behalf of the Office of Public Counsel appearing in the 01, 02, 03 and 07 dockets.

MS. KAUFMAN: Good morning. Vicki Gordon Kaufman of the McWhirter, Reeves Law Firm. I'm appearing on behalf of the Florida Industrial Power Users Group in the 01, 02 and 07 dockets, and appearing with me in the 01 docket is Joseph McGlothlin of our firm.

CHAIRMAN BAEZ: Thank you, Ms. Kaufman. Is there anyone else that needs to enter an appearance at this time?

MR. BUTLER: Chairman Baez, I'm sorry, but I need to add that Ms. Smith also is appearing on behalf of FPL in the 02 docket.

CHAIRMAN BAEZ: Very well. Let the record reflect.

Now we can move on to some preliminary matters.

MS. BROWN: Mr. Chairman, if we might enter an appearance on behalf of the Commission.

CHAIRMAN BAEZ: Of course, and I'm sorry.

MS. BROWN: That's all right. I'm Martha Carter Brown appearing for the Commission in the 02 and 04 dockets.

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

CHAIRMAN BAEZ: Are there any changes or

clarifications that need to be made to the comprehensive exhibit list? Seeing none, show the exhibit titled "Comprehensive Exhibit List" marked as Exhibit 1. That exhibit containing sequential numbering of the balance of the hearing exhibits as set forth in the prehearing order, those would be Exhibits 2 through 17 and, without objection, show them accepted into the record.

(Exhibits 1 through 17 marked for identification and admitted into the record.)

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**FLORIDA POWER & LIGHT COMPANY**

**TESTIMONY OF KOREL M. DUBIN**

**DOCKET NO. 040007-EI**

**APRIL 1, 2004**

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

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as the Manager of Regulatory Issues in the Regulatory Affairs Department.

**Q. Have you previously testified in the predecessors to this docket?**

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review and approval the Environmental Compliance True-Up Costs associated with FPL Environmental Compliance activities for the period January through December 2003.

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

A. Yes, I have. It consists of eight forms. Form 42-1A reflects the final true-up for the period January through December 2003. Form 42-2A consists of the final true-up calculation for the period. Form 42-3A consists of the calculation of the Interest Provision for the period. Form 42-4A reflects the calculation of variances between actual and estimated/actual costs for O&M Activities. Form 42-5A presents a summary of actual monthly costs for the period for O&M Activities. Form 42-6A reflects the calculation of variances between actual and estimated/actual costs for Capital Investment Projects. Form 42-7A presents a summary of actual monthly costs for the period for Capital Investment Projects. Form 42-8A consists of the calculation of depreciation expense and return on capital investment. Form 42-8A, Pages 27 through 29 provides the beginning of period and end of period depreciable base by production plant name, unit or plant account and applicable depreciation rate or amortization period for each Capital Investment Projects.

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

A. Unless otherwise indicated, the actuals data are taken from the books and records of FPL. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of

Accounts as prescribed by this Commission.

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

A. Form 42-1A, entitled "Calculation of the Final True-up" shows the calculation of the Net True-Up for the period January 2003 through December 2003, an over-recovery of $43,877 which I am requesting to be included in the calculation of the Environmental factors for the January 2005 through December 2005 period.

The actual End-of-Period over-recovery for the period January 2003 through December 2003 of $894,810 (shown on Form 42-1A, line 3) less the estimated/actual End-of-Period over-recovery for the same period of $850,933 (shown on Form 42-1A, line 6) results in the Net True-Up over-recovery for the period January 2003 through December 2003 (shown on Form 42-1A, line 7) of $43,877.

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

A. Yes. Form 42-2A, entitled "Calculation of Final True-up Amount", shows the calculation of the Environmental End of Period true-up for the period January 2003 through December 2003. The End of Period true-up shown on page 2 of 2, Lines 5 plus 6 is an over-recovery of $894,810. Additionally, Form 42-3A, Pages 1 of 2 and 2 of 2 shows the calculation of the Interest Provision of ($29,012), applicable to end of period true-up

over-recovery of $894,810.

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

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

**Q. Has the Company made any changes to the mechanism used to calculate depreciation and amortization in the Environmental Cost Recovery Clause (ECRC)?**

A. Yes. In July 2003 the Company changed the mechanism used to calculate depreciation and amortization for ECRC assets from a manual system to identifying the assets in the Company's Capital Asset Tracking System (CATS). This was done to improve the accuracy of the depreciation and amortization calculations and to ensure that ECRC assets are properly tracked during their useful lives.

**Q. Has the implementation of CATS required the Company to make an adjustment to its ECRC depreciation and amortization expenses?**

A. Yes. Prior to July 2003, the calculation of depreciation and amortization on the assets in the ECRC was on a one month lag because of when the data was available under the manual system. With the implementation of

CATS, the one month lag was eliminated and as a result, a "catch-up" adjustment was recorded in July 2003. The adjustment increased depreciation and amortization expense recorded for the month of July for each project by approximately twice what was recorded in June 2003 under the old manual system. The increase in July 2003 depreciation and amortization expense for all projects was approximately $235,000.

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

A. Yes, they are.

**Q. How did actual expenditures for January through December 2003 compare with FPL's estimated/actual projections as presented in previous testimony and exhibits?**

A. Form 42-4A shows that total O&M project costs were $254,602, or 5.8% lower than projected and Form 42-6A shows that total capital investment project costs were $74,466, or 1.3% higher than projected. Following are explanations for those O&M Projects and Capital Investment Projects with significant variances. Individual project variances are provided on Forms 42-4A and 42-6A. Return on Capital Investment, Depreciation and Taxes for each project for the actual period January 2003 through December 2003 are provided on Form 42-8A.

**1. Air Operating Permit Fees - O & M (Project 1)**

Project expenditures were $165,672, or 8.4% lower than anticipated. This variance is primarily due to fluctuations in permit fees for 2003, which are based on tons of pollutants discharged from the fossil fuel fired power plants during the previous year. These emissions are proportionate to the type of fuel used at each plant and variables fluctuate daily, based on weather conditions and fuel type. As a result of the Fort Myers Plant and Sanford Plant repowerings, less residual oil and, therefore, more natural gas was burned than expected at these sites. Because natural gas produces fewer emissions than residual oil, permit fees were less than expected.

**2. Continuous Emission Monitoring Systems (CEMS) - O & M (Project 3a)**

Project expenditures were $110,456, or 17.3% lower than anticipated. This variance is primarily due to the delay of Data Acquisition and Handling System (DAHS) software installation related to the DAHS GE Energy Services maintenance contract in 2003 due to contract negotiations with the vendor. The installation of DAHS servers at FPL facilities was delayed until December of 2003 which deferred the software installation to 2004.

**3. Maintenance of Stationary Above Ground Fuel Storage Tanks - O&M (Project 5a)**

Project expenditures were $224,008, or 73.2% lower than anticipated. An out-of-service tank inspection at the Riviera Plant was deferred to 2004 due to outage constraints.

**4. Oil Spill Cleanup/Response Equipment - O&M (Project 8a)**

Project expenditures were $61,308, or 36.3% lower than projected. The replacement of a containment boom, boat maintenance, and the re-supply of consumables were deferred to 2004 due to a delay in the project schedule. This delay was primarily caused by emergency work on a leak in the Martin 30" pipeline at the Riviera plant which prevented the scheduled work.

**5. Resource Conservation and Recovery Act (RCRA) Corrective Action - O&M (Project 13)**

Project expenditures were $11,083, or 21.1% higher than anticipated. This variance is primarily due to accelerating the project schedule, which allowed more work to be completed in a shorter time frame.

**6. NPDES Permit Fees - O&M (Project 14)**

Project expenditures were $19,000, or 15.4% higher than anticipated. NPDES Permit Fees for the St Lucie Plant were inadvertently excluded from the 2003 estimated/actual filing.

**7. Disposal of Non-Containerized Liquid Waste - O&M (Project 17a)**

Project expenditures were $138,560, or 60.5% higher than anticipated. More waste material than expected was encountered at the Manatee Plant causing higher than projected removal activities.

**8. Substation Pollutant Discharge Prevention & Removal – Distribution - O&M (Project 19a)**

Project expenditures were $228,356, or 22.8% higher than projected. This variance is primarily due to the utilization of an additional vendor to repair leaks in situations where equipment clearances were not needed in order to perform the work.

**9. Substation Pollutant Discharge Prevention & Removal - Transmission - O&M (Project 19b)**

Project expenditures were $224,978, or 33.2% lower than projected. There was no project activity during the months of March and April due to a delay in the project schedule caused by extended contract negotiations with the vendor which caused the vendor to become unavailable to work on the project. These months usually present prime weather conditions to obtain equipment clearances. Unavailability of equipment clearances limits the capability to perform planned project work.

**10. Amortization of Gains on Sales of Emission Allowances – O&M**

Amortization recorded during the period was $51,853, or 12.0% higher than projected. This variance is due to higher than anticipated gains from the DOE sales of emission allowances for 2003.

**11. Pipeline Integrity Management (PIM) – O&M (Project 22)**

Project expenditures were $105,000, or 144.3% higher than projected. Project engineering and design took longer than expected and was completed later than expected in 2002. Billing for this work had to be deferred to 2003 and the expense was recorded in 2003.

**12. Spill Prevention, Control, and Countermeasures (SPCC) – O&M (Project 23)**

Project expenditures were $84,589, or 110.9% higher than projected. Engineering study expenses related to the preliminary assessment of required modifications to tank liners were increased due to the inclusion of Spill Saturation Modeling of drainage inside secondary containments.

**13. Low NOx Burner Technology – Capital (Project 2)**

Project depreciation and return on investment were $107,187, or 5.2% higher than anticipated. This variance is primarily due to the adjustment to depreciation and amortization expense made in July due to the implementation of the CATS system. The adjustment increased

depreciation and amortization expense recorded for the month of July to approximately twice what was recorded in June 2003 under the old manual system.

**14. Continuous Emissions Monitoring Systems – Capital (Project 3b)**

Project depreciation and return on investment were $45,800, or 3.1% higher than anticipated. This variance is primarily due to the adjustment to depreciation and amortization expense made in July due to the implementation of the CATS system. The adjustment increased depreciation and amortization expense recorded for the month of July to approximately twice what was recorded in June 2003 under the old manual system.

**15. Maintenance of Above Ground Fuel Storage Tanks – Capital (Project 5b)**

Project depreciation and return on investment were $28,865, or 1.9% higher than anticipated. This variance is primarily due to the adjustment to depreciation and amortization expense made in July due to the implementation of the CATS system. The adjustment increased depreciation and amortization expense recorded for the month of July to approximately twice what was recorded in June 2003 under the old manual system.

**16. Pipeline Integrity Management (PIM) – Capital (Project 22)**

Project depreciation and return on investment were $11,062, or 100.0% lower than anticipated. Activities projected for 2003 were deferred to 2004, resulting in the 100.0% variance.

**17. Spill Prevention, Control, and Countermeasures (SPCC) – Capital (Project 23)**

Project depreciation and return on investment were $102,185, or 64.0% lower than anticipated. Activities projected to be completed and placed in service in 2003 were not completed, resulting a lower than projected plant-in-service for 2003. The installation of the high density polyethylene (HDPE) liner system in the secondary containment around tanks 901 & 902 at the Port Everglades plant was deferred to 2004 due to interferences with other work in the tank farm, and the HDPE liner installation at the Lauderdale plant tank 2 & 3 was deferred to 2004 due to soil remediation in the secondary containment area.

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

A. Yes, it does.

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**FLORIDA POWER & LIGHT COMPANY**

**TESTIMONY OF KOREL M. DUBIN**

**DOCKET NO. 040007-EI**

**August 4, 2004**

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

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Regulatory Issues in the Regulatory Affairs Department.

**Q. Have you previously testified in this docket?**

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review and approval the Environmental Estimated/Actual True-up Costs associated with FPL Environmental Compliance activities for the period January 2004 through December 2004.

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

A. Yes, I have. The exhibit consists of eight documents, PSC Forms 42-1E through 42-8E, included in Appendix I. Form 42-1E provides a summary of the Estimated/Actual True-up amount for the period January 2004 through December 2004. Forms 42-2E and 42-3E reflect the calculation of the Estimated/Actual True-up amount for the period. Forms 42-4E and 42-6E reflect the Estimated/Actual O&M and Capital cost variances as compared to original projections for the period. Forms 42-5E and 42-7E reflect jurisdictional recoverable O&M and Capital project costs for the period. Form 42-8E (pages 1 through 35) reflects return on capital investments, depreciation, and taxes by project.

**Q. Please explain the calculation of the ECRC Estimated/Actual True-up amount you are requesting this Commission to approve.**

A. Forms 42-2E and 42-3E show the calculation of the ECRC Estimated/Actual True-up amount. The calculation for the Estimated/Actual True-up amount for the period January 2004 through December 2004 is an underrecovery, including interest, of $103,793 (Appendix I, Page 4, line 5 plus line 6). This Estimated/Actual True-up underrecovery of $103,793 consists of January through June 2004 actuals and revised estimates for July through December 2004, compared to original projections for the same period.

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

A. Yes, with the exception of the inclusion of the CWA 316(b) Phase II Rule Project which is discussed in FPL's petition for approval dated June 21, 2004 and supported in the affidavit of Randall R. LaBauve, filed along with FPL's petition. Per FPL's petition, $500,000 of O&M costs associated with this project have now been included in the estimates for July through December 2004, whereas no costs for the project were included in the original 2004 projections.

**Q. How do the Estimated/Actual project expenditures for January 2004 through December 2004 period compare with original projections?**

A. Form 42-4E (Appendix I, Page 7) shows that total O&M project costs were $718,890 or 12.9% higher than projected and Form 42-6E (Appendix I, Page 10) shows that total capital investment project costs were $695,248 or 8.3% lower than projected. Below are variance explanations for those O&M Projects and Capital Investment Projects with significant variances. Individual project variances are provided on Forms 42-4E and 42-6E. Return on Capital Investment, Depreciation and Taxes for each project for the Estimated/Actual period are provided as Form 42-8E (Appendix I, Pages 13 through 47).

**1. Air Operating Permit Fees (Project No. 1) - O & M**

Project expenditures are estimated to be $189,254 or 9.2% lower than previously projected. The process for estimating air permit fees has been refined in order to produce more accurate estimates.

**2. Continuous Emissions Monitoring Systems (Project No. 3a) - O&M**

Project expenditures are estimated to be $79,952 or 12.6% higher than previously projected primarily due to higher than originally projected payments to the software vendor for technical support.

**3. Maintenance of Stationary Above Ground Fuel Storage Tanks (Project No. 5a) - O&M**

Project expenditures are estimated to be $485,412 or 105.4% higher than previously projected. This project includes performing required repairs identified during tank inspections. The variance is primarily due to an updated estimate of the costs associated with the required repairs, based on the results of tank inspections.

**4. RCRA Corrective Action (Project No. 13) - O&M**

Project expenditures are estimated to be $50,002 or 100.0% higher than previously projected. This variance is primarily due an increase in projected costs associated with the preparation of the Manatee and Sanford facilities for an assessment by the EPA. These expenditures are

contingent upon receiving notification from EPA of the intent to move forward with the process and were not included in the original projections.

**5. Substation Pollutant Discharge Prevention & Removal – Distribution (Project No. 19a) - O&M**

Project expenditures are estimated to be $34,386 or 3.0% higher than projected. The project was accelerated in the first half of the year to take advantage of good weather. Equipment clearances were obtained which would not be available during the storm season.

**6. Substation Pollutant Discharge Prevention & Removal – Transmission (Project No. 19b) - O&M**

Project expenditures are estimated to be $21,012 or 2.8% higher than projected. The project was accelerated in the first half of the year to take advantage of good weather. Equipment clearances were obtained which would not be available during the storm season.

**7. Wastewater Discharge Elimination & Reuse (Project No. 20) - O&M**

Project expenditures are estimated to be $40,000 or 80.0% lower than projected. The installation of the Electrostatic Precipitators (ESPs) at the Port Everglades Plant may result in less ash sluice water going to treatment basins, thereby reducing the amount of treated ash sluice water available for reuse. Once the ESP is operational, analyses will be

performed to determine the amount of sluice water available for reuse at the plant. This project will be deferred until information resulting from the analyses is obtained.

**8. Amortization of Gains on Sales of Emissions Allowances – O&M**

The variance of $276,180 or 64.2% higher than projected is primarily due to higher than anticipated gains from the DOE sales of emission allowances in 2004.

**9. Pipeline Integrity Management (Project No. 22) - O&M**

Project expenditures are estimated to be $180,225 or 450.5% higher than projected. A failure and oil spill at the Martin 30" pipeline required a response and repair. In order to ensure the integrity of the pipeline following repair, a complete analysis of the pipeline was required. This analysis was originally projected for 2005 but was accelerated.

**10. Spill Prevention, Control, and Countermeasures - SPCC (Project No. 23) - O&M**

Project expenditures are estimated to be $64,571 or 25.8% lower than projected. The EPA has extended the deadlines for SPCC compliance. SPCC Plans will now be due in August 2005 and the facility upgrades will be due in February 2006. Costs associated with the development of SPCC plans which were included in the original projections have shifted

to 2005.

**11. Lowest Quality Water Source (LQWS) (Project No. 27) – O&M**

The variance of $68,370 or 18.5% lower than projected is primarily due to a delay in the permitting for Reclaimed Water Use at the Cape Canaveral Plant. The plant was not able to use the lowest quality water source during the first and second quarters of 2004, which resulted in lower than projected expenditures.

**12. Continuous Emission Monitoring Systems (Project No. 3b) - Capital**

The variance in depreciation and return is $46,634, or 3.2% lower than projected. $126,336 of CEMS equipment retirements at various plants was not included in the original projections. Additionally, $473,948 of 7-year amortizable CEMS equipment retirements are estimated for August 2004 which were not included in the original projections.

**13. Maintenance of Stationary Above Ground Fuel Storage Tanks (Project No. 5b) - Capital**

The variance in depreciation and return of $98,519, or 6.1% lower than projected is primarily due to actual retirements of $531,139 for the Port Everglades GT units. These retirements were not included in the original projections.

**14. Oil Spill Cleanup/Response Equipment (Project No. 8b) - Capital**

The variance in depreciation and return of $26,484 or 18.7% lower than projected is primarily due to $86,208 of 7-year amortizable retirements at Martin common which are now estimated to occur in August 2004. These retirements were not included in the original projections.

**15. $SO_2$ Allowances – Negative Return On Investment - Capital**

The variance in depreciation and return is $25,788 or 20.0% higher than projected due to higher than anticipated gains from the DOE sales of emission allowances in 2004.

**16. Disposal of Noncontainerized Liquid Waste (Project No. 17b) - Capital**

The variance of $3,025 or 11.0% lower than projected is primarily due to $311,009 of 7-year amortizable retirements of general plant equipment which are now estimated to occur in August 2004. These retirements were not included in the original projections.

**17. Wastewater Discharge Elimination & Reuse (Project No. 20) - Capital**

The variance in depreciation and return is $79,207 or 28.7% lower than projected. This variance is primarily due to timing differences. Wastewater reuse system installations at the Martin and Cape Canaveral

Plants which were originally projected to go in-service in January 2004 are now projected for December 2004.

**18. Pipeline Integrity Management (Project No. 22) - Capital**

The variance in depreciation and return is $99,690 or 98.5% lower than projected. This variance is primarily due to the deferral of most of the work planned for 2004 to 2005. The hydraulic study and meter testing for the Martin 30" pipeline was completed and results determined that the installation of positive displacement meters was required. These meters needed to be special ordered. Additionally, the study and testing determined that some of the pipeline system needs to be modified with new valves and piping to accommodate the meter system as well as some instrumentation. The meters are a long lead time item and due to the lead time and requirements for having to take the 30" pipeline out of service to perform the work it was determined that this work needed to be moved to 2005.

**19. Spill Prevention, Control, and Countermeasures - SPCC (Project No. 23) - Capital**

The variance in depreciation and return is $376,102 or 28.0% lower than projected. This variance is primarily due to the timing of additions which resulted in the average plant balance being lower than originally projected. Projects that were originally anticipated to go in-service during the prior reporting period will now be placed in service this reporting period. The reduction in the average plant balance due to timing

differences was partially offset by the additional of activities (double-wall fuel oil piping at Riviera Plant Units 3 and 4, Sanford Plant Unit 3, and Cape Canaveral Plant, and fuel oil piping sheet pile diversion at Manatee Plant) which were not included in the original projections.

**20. Manatee Reburn (Project No. 24) - Capital**

The variance is estimated to be $299,991 or 97.8% higher than projected. This variance is due to timing differences - a larger portion of the expenditures being made in the earlier months of 2004 which were projected to be made later in the year, thereby increasing the return on investment.

**21. Pt. Everglades ESP Technology (Project No. 25) - Capital**

The variance is estimated to be $228,739 or 20.9% lower than projected. This variance is due to timing differences - a larger portion of the expenditures being made in the later months of the year which were projected to be made earlier in the year, thereby decreasing the return on investment.

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

A. Yes, it does.

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**FLORIDA POWER & LIGHT COMPANY**

**TESTIMONY OF KOREL M. DUBIN**

**DOCKET NO. 040007-EI**

**SEPTEMBER 9, 2004**

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

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Regulatory Issues in the Regulatory Affairs Department.

**Q. Have you previously testified in this docket?**

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review FPL's Environmental Cost Recovery Clause (ECRC) projections for the January 2005 through December 2005 period.

**Q. Is this filing by FPL in compliance with Order No. PSC-93-1580-FOF-**

**EI, issued in Docket No. 930661-EI?**

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

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

A. Yes. It consists of seven documents, PSC Forms 42-1P through 42-7P provided in Appendix I. Form 42-1P summarizes the costs being presented at this time. Form 42-2P reflects the total jurisdictional costs for O&M activities. Form 42-3P reflects the total jurisdictional costs for capital investment projects. Form 42-4P consists of the calculation of depreciation expense and return on capital investment for each project. Form 42-5P gives the description and progress of environmental compliance activities and projects for the projected period. Form 42-6P reflects the calculation of the energy and demand allocation percentages by rate class. Form 42-7P reflects the calculation of the ECRC factors.

**Q. Please describe Form 42-1P.**

A. Form 42-1P (Appendix I, Page 2) provides a summary of projected environmental costs being presented for the period January 2005 through December 2005. Total environmental costs, adjusted for revenue taxes, amount to $24,928,600 (Appendix I, Page 2, Line 5a) and include $24,476,832 of environmental project costs (Appendix I, Page 2, Line 1c) increased by the estimated/ actual under-recovery of $103,793 for the

January 2004 - December 2004 period as filed on August 4, 2004 (Appendix I, Page 2, Line 2) and decreased by the final over-recovery of $43,877 for the January 2003 – December 2003 period as filed on April 1, 2004 (Appendix I, Page 2, Line 3).

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

A. Form 42-2P (Appendix I, Pages 3 and 4) presents the environmental project O&M costs for the projected period along with the calculation of total jurisdictional costs for these projects, classified by energy and demand. Form 42-3P (Appendix I, Pages 5 and 6) presents the environmental project capital investment costs for the projected period. Consistent with FPL's 2002 Rate Agreement, FPL is using the 2002 capital cost and capital structure from the December, 2002 Surveillance Report to calculate the return on assets included in FPL's Environmental Cost Recovery Clause. Form 42-3P also provides the calculation of total jurisdictional costs for these projects, classified by energy and demand.

The method of classifying costs presented in Forms 42-2P and 42-3P is consistent with Order No. PSC-94-0393-FOF-EI.

**Q. Please describe Form 42-4P.**

A. Form 42-4P (Appendix I, Pages 7 through 41) presents the calculation of depreciation expense and return on capital investment for each project for the projected period.

**Q. Please describe Form 42-5P.**

A. Form 42-5P (Appendix I, Pages 42 through 73) provides the description and progress of environmental projects included in the projected period.

**Q. Please describe Form 42-6P.**

A. Form 42-6P (Appendix I, Page 74) calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate contributes to total kWh sales, as adjusted for losses, for each rate class.

**Q. Please describe Form 42-7P.**

A. Form 42-7P (Appendix I, Page 75) presents the calculation of the proposed ECRC factors by rate class.

**Q. Are all costs listed in Forms 42-1P through 42-7P attributable to Environmental Compliance projects previously approved by the Commission?**

A. Yes, with the exception of the Selective Catalytic Reduction (SCR) Consumables Project and CWA 316(b) Phase II Rule Projects. The SCR Consumables Project is presented in the testimony of R. R. LaBauve which is being filed contemporaneously with my testimony. FPL filed for approval of the CWA 316(b) Phase II Rule Project on June 21, 2004. The

Commission is scheduled to address this project at the September 21, 2004 Agenda Conference. All of the projected costs for these projects in the projected period are O&M costs, so they are included on Schedule 42-3P as follows:

| | |
|---|---|
| CWA 316(b) Phase II Rule | **Project No. 28** |
| **SCR Consumables** | **Project No. 29** |

**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. 040007-EI**

**September 9, 2004**

**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 testified in predecessors to this docket?**

A. Yes.

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

A. The purpose of my testimony is to present for Commission review and approval FPL's plans for a new environmental project – the Selective Catalytic Reduction (SCR) Consumables 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 Martin Unit 8 **Power Plant Siting Application No.** PA 89-27A - Final Order of **Certification and excerpt from Conditions** of Certification – Section IV - Air.

- **Document RRL-2 - 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 XXIII - Air.

- Document RRL-3 - Drawing of a typical SCR module.

**Q. Please describe the law or regulation requiring the SCR Consumables Project.**

A. The Manatee Unit 3 and Martin Unit 8 Expansion Project Final Orders of Certification under the Florida Power Plant Siting Act and the Prevention of Significant Deterioration (PSD) Air Construction Permit require the installation of SCRs on each of the plants' four Heat Recovery System Generators (HRSG) for the control of nitrogen oxide (NOx) emissions. The Florida Department of Environmental Protection (FDEP) made the determination that the SCR system is considered Best Available Control Technology (BACT) for these types of units, with concurrence from the

US Environmental Protection Agency (EPA). As discussed below, operation of the SCRs requires FPL to incur O&M costs for certain products that are consumed in the SCRs.

**Q. What alternatives to the installation of SCRs did FPL consider for Manatee Unit 3 and Martin Unit 8?**

A. As part of the Best Available Control Technology (BACT) identification process with both FDEP and EPA, FPL was required to evaluate the various technologies available for NOx emission controls. In this determination the SCR system in combination with Dry Low NOx burners in the combustion turbines represent the best available control technology when considering engineering, the environment, and the economics. Other alternatives considered include other non-ammonia type catalytic, reactive, or absorption reactive processes. These alternatives were determined to be either technically and or economically not feasible by FDEP and EPA.

**Q. Please describe the SCR system that is installed at Manatee Unit 3 and Martin Unit 8.**

A. The SCR system is comprised of essentially two components. The first component is an array of porous catalyst material installed inside the Heat Recovery Steam Generator (HRSG), where all combustion exhaust flows through as it moves from the inlet duct to the exhaust stack. This array consists of 22 "blocks" that are placed into two columns of 11 blocks

each. These blocks are impregnated with chemical elements that are needed to reduce the $NO_X$ pollutants back to nitrogen and water vapor.

The second component consists of ammonia injection nozzles and associated piping. Anhydrous ammonia is blended with air and is injected upstream of the catalyst blocks through nozzles that are mounted through the sides of the HRSG. This ammonia mixes with the exhaust gases, and a chemical reduction reaction occurs on the surface of the catalyst.

Downstream of the SCR, located in the exhaust stack of the HRSG, Continuous Emissions Monitoring System (CEMS) equipment is mounted to continuously monitor the effectiveness of the SCRs. Per the Final Orders of Certification, $NO_X$ concentrations in the exhaust are to be maintained at 2.5 parts per million. Additionally, the PSD Air Construction Permit limits the unreacted ammonia from the process, or slip target, to less than 5 parts per million, which is confirmed by annual stack testing conducted in accordance with the EPA.

**Q. What O&M costs does FPL seek to recover through the SCR Consumables Project?**

A. FPL is seeking recovery of O&M costs associated with consumable goods necessary to operate the SCR systems at Manatee Unit 3 and Martin Unit 8. These include anhydrous ammonia, calibration gases, and equipment wear parts requiring periodic replacement such as controllers, ammonia

detectors, heaters, pressure relief valves, dilution air blower components, NOx control analyzers and components.

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

A. The bulk supply and storage of anhydrous ammonia to each of the sites will be competitively bid with qualified suppliers to ensure a safe, reliable and least-cost supply. Additionally, the monitoring requirements previously discussed will help to ensure optimum injection rates of anhydrous ammonia in the SCR system, thus helping to minimize the consumption of anhydrous ammonia in the process.

**Q. What are the compliance dates for this project?**

A. The SCR systems are required to be operational whenever the units operate in the combined cycle mode. Manatee Unit 3 and Martin Unit 8 startup and commissioning is scheduled for early 2005. The expected commercial operation date for both Manatee Unit 3 and Martin Unit 8 is March 2005.

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

A. FPL has projected total annual O&M costs of $292,000 per plant, or a total of $584,000 for both plants, associated with the consumable goods necessary to operate the SCR systems at Manatee Unit 3 and Martin Unit 8. These O&M costs will begin once Manatee Unit 3 and Martin Unit 8

start commercial operations in March 2005 and the SCR systems become operational. The first full year of operation for both units will be 2006.

**Q. Has FPL estimated how much will be spent on the Project in 2005?**

A. FPL has projected O&M costs of $243,335 per plant, or a total of $486,670, associated with the consumable goods necessary to operate the SCR systems at Manatee Unit 3 and Martin Unit 8.

**Q. Is FPL recovering through any other mechanism the costs for the SCR Consumables Project for which it is petitioning for ECRC recovery?**

A. No.

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

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 040007-EI
April 1, 2004

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, 2003 through December 31, 2003.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2003 through December 2003 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 $8,416,756, as compared to the actual recoverable capital costs of $8,409,779. This results in a variance of ($6,977).

Q. Please explain the capital project variance of ($6,869) in Continuous Emission Monitoring (Line Item 1.5).

A. This deviation resulted from postponing the Plant Crist Units 6&7 Continuous

Emission Monitoring (CEM) gas analyzer replacement project until 2004. The project was delayed because the Unit 7 precipitator project construction could have possibly damaged the new equipment. Delaying the installation of the monitors will ensure that they are not damaged by current construction activities.

Q. Please explain the variance of $1,439 in the Crist DEP Project (Line Item 1.19)

A. The Crist DEP project qualified for Allowance for Funds Used During Construction (AFUDC). The initial phase of the project was placed in service ahead of schedule in December of 2003. At that time it was included in the Environmental Cost Recovery Clause (ECRC). The remaining first phase is projected to be placed in service during the first half of 2004. As pieces of this project move into Plant In Service (PIS), they will be included in the ECRC.

Q. How do the actual O&M expenses for the period January 2003 to December 2003 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 $2,637,219, as compared to the estimated true-up of $2,900,377. This results in a year-end variance of ($263,158). I will address eight O&M projects and programs that contribute to this variance.

Q. Please explain the variance of $4,454 in Sulfur (Line Item 1.1).

A. Sulfur injection into the flue gas enhances the collection efficiency of the Crist Unit 7 electrostatic precipitator when burning low sulfur coal. Sulfur use is dependent on the quality and content of the fuel supply at Plant Crist. Plant Crist used the sulfur injection system more than was originally anticipated during 2003.

Q. Please explain the variance of ($2,300) in Asbestos Fees (Line Item 1.4).

A. Gulf anticipated being required to submit additional asbestos notifications during 2003 as a result of the renovations required for the Plant Crist Unit 7 precipitator project. These notifications were not necessary, and resulted in a ($2,300) deviation.

Q. Please explain the variance of ($47,056) 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 Plants Smith and Daniel. Based on good performance, greater than 7.5% relative accuracy, the testing frequency was reduced to one annual test per unit. This reduced testing schedule resulted in a deviation in the Emission Monitoring category.

Q. What caused the variance of ($154,117) in the category entitled General Water Quality (Line Item 1.9).

A. The Plant Smith State Pollution Discharge Elimination System (SPDES) permit renewal was submitted during 2003. Gulf Power projected additional

expenses related to water quality issues prior to the Florida Department of Environmental Protection (FDEP) issuing the permit. However, Gulf Power did not incur any additional water quality expenses associated with the SPDES permit renewal during 2003 resulting in a deviation in the General Water Quality category.

Q. Please explain the variance of ($3,920) in the category entitled Lead and Copper Rule (Line Item 1.9).

A. This variance is due to chemical usage costs for corrosion control treatment in the potable water system at Plants Crist and Smith being less than the projected expenses.

Q. Please explain the variance of ($41,735) 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 generating facilities being less than originally anticipated.

Q. Please explain the variance of ($8,955) in the category entitled Above Ground Storage Tanks (Line Item 1.12).

A. This deviation primarily resulted from postponing tank inspections from 2003 to 2004. The American Petroleum Institute 653 in-service tank inspections required by Chapter 62-761, Florida Administrative Code, were postponed from fourth quarter 2003 to first quarter 2004 due to scheduling conflicts with the contractor. This deviation was offset by the costs required to coat the sulfuric acid tank concrete containment at Plant Smith. These coating costs

were not included in the 2003 projection.

Q. Please explain the variance of $3,153 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 necessity for sodium injection based on the current coal supply was more than what was anticipated for the projection period.

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. 040007-EI
August 4, 2004

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 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 estimated true-up for the period from January 1, 2004 through December 31, 2004. 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, 2004 through December 31, 2004 with approved projected amounts.

A. As reflected in Mrs. Davis' Schedule 6E, the recoverable capital costs approved in the original projection total $11,593,128, as compared to

the estimated true-up amount of $12,429,822. This results in a projected variance of $836,694. There are six capital projects and programs that contributed to the majority of this variance- Low NOx burners, Crist 6&7; Continuous Emission Monitoring; Smith Waste Water Treatment Facility; and finally, Crist FDEP Agreement. These variances are discussed below.

Q. Please explain the variance of ($108,353) in the capital category entitled Low NOx burners, Crist 6&7 (Line Item 1.4).

A. The Low NOx burner variance resulted from under estimating the Plant Crist Unit 7 Low NOx burner retirement.

Q. Please explain the capital project variance of ($40,457) in Continuous Emission Monitoring (Line Item 1.5).

A. The Continuous Emission Monitoring (CEMs) variance resulted from postponing the Plant Daniel Units 1 and 2 gas analyzers replacement (PE 1560) until the fall outage. This deviation was partially offset by adding the Plant Crist Continuous Assurance opacity monitor to the CEMs budget projection. The Compliance Assurance Monitoring (CAM) requirements under Title V of the Clean Air Act require a method of continuously monitoring particulate emissions. Opacity can be used as a surrogate parameter if the facility demonstrates a correlation between opacity and particulate matter. This method of monitoring is less capital intensive than a stand alone continuous particulate compliance monitor

Q. Please explain the capital project variance of $5,153 or 26.3% in the Smith Waste Water Treatment Facility (Line Item 1.5).

A. The existing Plant Smith domestic waste water treatment facility is designed to operate at a maximum capacity of 3,000 gallons per day. The plant is planning to upgrade the domestic treatment system because the current system load frequently exceeds the maximum daily capacity, which may result in potential exceedances of Plant Smith's State Pollution Discharge Elimination System (SPDES) permit. This upgrade was not included in the 2004 ECRC projection filing creating a variance in the Smith Waste Water Treatment Facility line item.

Q. Please explain the variance of $988,206 variance in the capital category entitled Crist FDEP Agreement for ozone attainment (Line Item 1.19).

A. The Crist FDEP Agreement variance is a result of the Plant Crist Unit 7 precipitator going into service ahead of our projected schedule.

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 $2,665,823 as compared to the original projection of $3,005,759. This will result in a year-end variance of ($339,936). There are six O&M projects and programs that contributed to the majority of this variance which I will discuss – General Water Quality; Auditing/Assessment; Sodium Injection; Gulf Coast Ozone Study (GCOS); SPCC Substation Project; and $SO_2$ Allowances.

Q. Please explain the ($75,000) variance in General Water Quality (Line Item 1.6).

A. The General Water Quality variance resulted from Plant Crist canceling a surface water project to investigate copper exceedances that occurred during the 2003 sampling events. Subsequent sampling events have not confirmed elevated copper concentrations, allowing postponement of the project.

Q. Please explain the variance of $5,382 or 107.6% in Auditing/Assessment (Line Item 1.10).

A. Two additional audits were conducted during the period that were not included in the 2004 budget projection. The auditing/assessment schedule is modified throughout the year.

Q. Please explain the variance of $13,473 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 chemical composition of the coal supply at Plant Smith during the first half of the year required sodium injection, although the plant does not anticipate the need for sodium injection during the remainder of the year.

Q. Please explain the variance of ($10,000) in Line Item 1.17, Gulf Coast Ozone Study (GCOS).

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

Q. Please explain what has contributed to the ($37,783) variance in the SPCC Substation Project (Line Item 1.18)?

A. The Century substation SPCC project has been postponed until electrical equipment can be removed from the site. Gulf Power is currently evaluating temporary power supply alternatives for use while the site is being dismantled and reconstructed.

Q. Please explain the ($243,239) variance in $SO_2$ allowances in Line Item 1.18?

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. 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. 040007-EI

September 3, 2004

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 have the responsibility for numerous environmental activities.

Q. Are you the same James O. Vick who has previously testified before this Commission on various environmental matters?

A. Yes.

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

A. The purpose of my testimony is to support Gulf Power Company's projection of environmental compliance costs recoverable through the Environmental Cost Recovery Clause (ECRC) for the period from January 2005 through December 2005.

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 NOx 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 Smith Consumptive Use Permit
- Northwest Florida Water Management District (NWFWMD) correspondence regarding the proposed Smith Water Conservation Plan.
- U.S. Fish and Wildlife Service correspondence regarding required changes to street lighting in the Panama City Beach area.
- Bay County Ordinance Number 02-07, establishing a sea turtle conservation zone and lighting ordinance.
- City of Destin, Florida ordinance relating to the regulation of outdoor lighting to protect marine turtles nesting in the Destin, Florida area.

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

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

A. A listing of the environmental capital projects which have been included in Gulf's ECRC calculations has been provided to Ms. Davis and are 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' schedules been previously approved by the Commission?

A. No. Gulf's 2005 ECRC capital projection includes both new projects and expansions of existing projects that have not been previously approved by the Commission. All of these projects are related to Gulf's existing Air and Water Quality programs, including Gulf's program for meeting the terms of its August 28, 2002 agreement (the "Agreement") with the FDEP. The purpose of the Agreement was to reduce NOx emissions at Gulf's Plant Crist to help ensure that Escambia and Santa Rosa counties are in compliance with the new eight hour ozone ambient air quality standard.

Q. Mr. Vick, please describe the new capital project associated with Gulf's NOx reduction agreement with FDEP that is part of Gulf's 2005 ECRC capital projection.

A. For the 2005 projection, we have included capital costs associated with the next phase of the Plant Crist FDEP Agreement for Ozone Attainment (PE 1287) which was developed 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 as approved by the Order is the implementation of NOx emission reduction strategies on Crist Units 4, 5, and/or 6 by May 1, 2006. The Agreement called for completion of an engineering feasibility study addressing NOx reduction technologies on these units necessary to enable the entire plant to meet an overall plant-wide NOx emission limit of 0.2 lbs/mmbtu. As noted in the Order, the Agreement further called for Gulf to ". . . obtain written concurrence from FDEP that the activities Gulf proposes to implement [for these units] are reasonable and necessary to achieve the emission limit . . ." specified in the Agreement.

Gulf conducted a three step feasibility study to determine the best and most cost effective technology to meet the facility wide emission limit for Plant Crist as outlined in the Agreement. Gulf considered the proven history of technologies, commercial availability, costs and NOx removal efficiency in determining a selected strategy. Our initial step compared available NOx reduction technologies including Selective Catalytic Reduction (SCR) which would likely achieve NOx emissions well below the targeted levels but at a cost of approximately $142/kw. The SCR costs were at least three times higher than other available NOx reduction technologies that were evaluated. Technology evaluations conducted on Rich Reagent Injection (RRI), Rotating Overfire Air (ROA), Rotamix, Low Nox Burners and Overfired Air, and Selective Non-Catalytic Reduction (SNCR) revealed that the RRI, ROA, and the Rotamix did not meet the required NOx emission reduction levels. Based on the study, Gulf

concluded that a new low NOx burner system with an Overfired Air configuration and SNCR technology produced the most cost beneficial and reliable strategy for Crist Unit 6. Gulf further concluded that the next most cost effective step would be to retrofit Units 4 & 5 with SNCR technology if necessary, to assure compliance with the Agreement.

Gulf Power received written concurrence from FDEP on August 10, 2004 that the SNCR, low NOx 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 area's compliance with the 8-hour ozone ambient air quality standard. A copy of the August 10 concurrence letter from FDEP is contained in my Exhibit, JOV-1. Gulf expects the Crist Unit 6 SNCR, low NOx burner/overfire air technologies totaling approximately $19 million to go in service in November 2005.

Q. Mr. Vick, please describe the next new capital project for 2005 that Gulf is asking be considered for cost recovery.

A. The next new project is shown on Ms. Davis' schedules under the title Precipitator Upgrades for Compliance Assurance Monitoring (CAM). 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 the CAM plan included in Gulf's Title V Air Permit renewal applications in June 2004.

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 is expected to be placed in service in May 2005. The second phase, the Smith Unit 1 precipitator upgrade, will be initiated in 2006 with an estimated completion date of April 2007. We also anticipate 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 for future recovery periods.

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

A. The next new project for 2005, the Smith Closed Loop Cooling Project (PE 1638), is an extension of Gulf's water conservation and consumptive use efficiency program at Plant Smith adopted pursuant to the Company's consumptive water use permit. As has been discussed in previous testimony, Plant Smith's consumptive use permit, issued by the NWFWMD, required Plant Smith to develop a plan for water conservation and efficiency measures by July 31, 2003. During plan development, Gulf Power reviewed several water conservation measures to determine the most cost effective compliance alternatives. The first such project was

the previously approved Shield Water Project. For the 2005 capital cost projection, we have renamed the line item category that contains the Shield Water Conservation Project to Smith Water Conservation and have expanded this category to include the new Closed Loop Cooling System at Plant Smith.

Currently, groundwater is used to cool steam cycle water samples. Plant Smith estimates that the proposed closed loop cooling system for the laboratory sampling system would reduce water consumption by approximately 80,000 gallons per day. 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 the project is $120,000. Correspondence from the NWFWMD regarding the Smith Closed Loop Cooling Project is included in my Exhibit, JOV-1.

Q. Mr. Vick, please identify any other expansions of previously approved capital projects for the projection period that are required for environmental compliance.

A. There are two other previously approved capital projects that will be expanded. These include the Plant Daniel Ash Management project and the Continuous Emission Monitoring (CEMs) replacements at Plant Crist, Plant Scholz and Plant Daniel.

On January 12, 1994 the FPSC granted ECRC approval for the recovery of the Daniel Ash Management Project in Order Number PSC-94-0044-

FOF-EI. The original project included the installation of a dry ash transport system, lining of the existing bottom of the ash pond, closure and capping of the existing fly ash pond, and the expansion of the landfill area.

Plant Daniel plans to construct a vertical expansion of the existing previously approved ash storage facility because the existing monofill is approaching the end of its storage capacity. In preparation for the completion and closure of the expansion area, Daniel must begin developing and permitting a new on-site ash storage facility. Expenditures for the existing monofill expansion and the engineering and design for the new storage facility are expected to be approximately $850,000.

During the 2005 recovery period the CEMs project includes the replacement of flow monitors at Plant Scholz (PE 1324 and PE 1325), the CEMs shelter for Units 4 and 5 at Plant Crist (PE 1217), and the installation of the Plant Daniel gas analyzers on Unit1 (PE 1570). The gas analyzer and flow monitors are necessary in order to provide the accuracy and reliability needed to measure SO2, NOx, CO2, opacity, and gas flow and further maintain compliance with the CAAA requirements. All of the existing analyzers and monitors are approaching the end of their useful life, and will be retired upon replacement.

Q. Please compare the Environmental Operation and Maintenance (O & M) activities listed on Schedule 2P of Ms. Davis' 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, except for the Cooling Water Intake Program that is included in the General Water Category and the Turtle Protective Lighting Program.

Q. Mr. Vick, please describe the regulation requiring the addition of the Cooling Water Intake Program that is included in the General Water Quality item (Line Item 1.6).

A. On July 9, 2004 the Environmental Protection Agency (EPA) published final regulations under the Clean Water Act Section 316(b) for cooling water intake structures at Phase II electric generating facilities. Phase II facilities include existing electric generating facilities with a cooling water intake structure that are designed to withdraw fifty million gallons per day (MGD) or more of water from waters of the United States for cooling purposes. The rule establishes national performance standards for reducing the impingement and entrainment of fish and shellfish and provides that EPA "shall require that the design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact" at existing Phase II facilities. Gulf's facilities that are subject to the rule include Plants Crist, Smith, and Scholz.

Gulf Power will be required to submit a Proposal for Information Collection (PIC) to the FDEP outlining Gulf's biological sampling and data collection plan. The biological and operational information collected will be summarized and reported to FDEP during the next National Pollution Discharge Elimination System (NPDES) permit cycle. An implementation strategy will also be developed during the next NPDES permit cycle. The projected expenses for the Cooling Water Intake Program during the 2005 recovery period total $234,602.

Q. Please describe the O & M activities included in the Air Quality category.

A. There are six O & M activities included in this category:

The first activity, Sulfur (Line Item 1.1) reflects operational expenses associated with the burning of low sulfur coal. This item refers to the flue gas sulfur injection system needed to improve the collection efficiency of the Plant Crist Unit 7 electrostatic precipitator for certain coals. Based on the expected coal supply for Plant Crist during 2005 there are no expenses projected for this activity during the 2005 recovery period.

The second activity listed 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.

The third activity included in the Air Quality category, Title V (Line Item 1.3), represents projected expenses associated with the implementation

of the Title V permits. The total estimated expense for the Title V Program during 2005 is $87,232.

The fourth activity listed 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.

The fifth activity listed on Schedule 2P, Emission Monitoring (Line Item 1.5), reflects an ongoing O & M expense associated with the Continuous Emission Monitoring equipment (CEM) as required by the CAAA. These expenses are incurred in response to EPA's requirements that the Company perform Quality Assurance/Quality Control (QA/QC) testing for the CEMs, including Relative Accuracy Test Audits (RATAs) and Linearity Tests. Other activities within this category include the testing, development, and implementation of new periodic monitoring requirements associated with the Clean Air Act Amendment. The expenses expected to occur during the 2005 recovery period for these activities total $534,249.

Q. Please identify any Air Quality O & M categories that have not previously been included in ECRC projection filings?

A. The sixth Air Quality activity, FDEP NOx Reduction Agreement (Line Item 1.20), is being included in the ECRC projection for the first time. This line item currently includes the O & M cost associated with the SCR project

that was included as part of the August 28, 2002 agreement with FDEP discussed earlier in my testimony with regard to capital projects. This O&M line item includes the cost of anhydrous ammonia, 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 proposed agency action order PSC-02-1396-PAA EI, issued October 9, 2002. The projected expenses for the 2005 recovery period total $757,241.

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 $600,140. The projected increased activity in this line item is related to the addition of the previously discussed Cooling Water Intake Program ($234,602) and the new arsenic groundwater standard ($50,000).

The FDEP has published a new groundwater standard for arsenic, which lowers the standard from 0.05 mg/L to 0.01 mg/L, effective January 1, 2005. Historical groundwater monitoring data from Plants Crist and 2006. Scholz indicate that these facilities may not be able to comply with the lower standard. Gulf is proposing to conduct a groundwater study

during 2005 at Plant Scholz and Plant Crist due to projected groundwater impacts exceeding the new arsenic standard. The study is necessary to determine the nature of the potential impacts to groundwater and to identify solutions necessary to resolve this issue. Gulf expects to incur future capital and O&M costs to ensure continued compliance with the groundwater standards.

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 $927,218.

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 $12,000 during the 2005 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 and is expected to incur $8,800 of expenses during the 2005 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. This program is a previously approved program that is projected to incur incremental expenses totaling $214,773.

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?

A. Yes. There are five other O & M categories which have been approved in past proceedings. They are Above Ground Storage Tanks, Low NOx, Ash Pond Diversion Curtains, Mercury Emissions, Sodium Injection System, and Gulf Coast Ozone Study (GCOS).

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 $106,200 of expenses during 2005.

Q. Please identify the activities included in the Low NOx (Line Item 1.13) category.

A. This project included the purchase and installation of Low NOx burner tips at Plant Crist on Units 4 and 5 and at Plant Smith on Unit 1 to comply with Phase II requirements of the CAAA. There are no expenses projected for this project during the 2005 recovery period.

Q. Please identify the activities included in the Ash Pond Diversion Curtains category, (Line Item 1.14).

A. This project refers to the installation of additional flow diversion curtains in the Plant Crist ash pond to effectively increase ash pond water retention time. Increased retention time allows for the sedimention and treatment process to be more effective in reducing levels of suspended particulate matter. There are no expenses projected for this project during the 2005 recovery period.

Q. Please identify the activity included in the Mercury Emissions (Line Item 1.15) category.

A. This program, approved by the Commission for recovery in Docket No. 981973-EI, pertains to requirements for Gulf to periodically analyze coal shipments for mercury and chlorine content. The EPA mandated that shipments of coal would be analyzed for mercury and chlorine only during 1999. No further notices of continued sampling requirements of coal shipments beyond 1999 have been issued by EPA, therefore no expenses have been planned for this activity in 2005.

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 at Plant Smith to enhance precipitator efficiencies when burning certain low sulfur coals at the plant. Based on coals expected to be used at Plant Smith during 2005, there are no projected expenses for the 2005 recovery period related to this activity.

Q. Please identify the activity included in the Gulf Coast Ozone Study (Line Item 1.17) category.

A. This program, approved for recovery in Docket No. 991834-EI for inclusion in the ECRC, involves a joint modeling analysis between Gulf Power and the State of Florida to provide an improved basis for assessment of eight-hour ozone air quality for Northwest Florida. The

project models past episodes of high ozone levels in Northwest Florida and will be used in developing potential control strategies for both stationary and mobile sources to provide a comprehensive evaluation of the area as required under Title I of the Clean Air Act. Gulf Power anticipates that the GCOS project will be completed by 2006. Expenses for this project during the 2005 recovery period are anticipated to be $20,000.

Q. Please identify the activity included in the SPCC Substation Project (Line Item 1.18).

A. The SPCC project included the expenses associated with installing additional containment and/or diversionary structures at substations to reduce the risk of a potential mineral oil discharge to navigable waters of the United States or adjoining shorelines. There are no projected expenses for this project during 2005.

Q. Please describe the activity included in the SO2 allowances (Line Item 1.21).

A. This program includes expenses for SO2 allowances for Gulf's plants. The expenses are offset by gains realized from the sale of SO2 allowances.

Q. Are there any additional O&M projects or programs that are included in the projection filing that have not been previously approved by the Commission?

A. Yes, Gulf has a new category for 2005 entitled Turtle Protective Lighting Program (Line Item 1.20). The Turtle Protective Lighting Program is necessary to meet the requirements of Title 50 Code of Federal Regulations Part 117, Endangered and Threatened Wildlife and Plants, and local County ordinances regulating artifical lighting in threatened and endangered sea turtle nesting areas. Gulf Power is requesting recovery of the cost to install protective sea turtle lighting in these nesting areas. The projected expenses for this project during the 2005 recovery period total $13,146. Gulf proposes these costs be allocated on a demand basis. A copy of the Destin and Bay County ordinances regulating artifical lighting along the coastal areas is included in my Exhibit, JOV-1. Correspondence from the U.S. Fish and Wildlife Service regarding required changes to street lighting in the Panama City Beach area is also included in my Exhibit, JOV-1.

Q. Are there any other project or program expenses resulting from either new or more stringent environmental regulations which may significantly increase O & M costs for the recovery period January 2005 through December 2005?

A. Gulf Power is not aware of any at this time.

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. 040007-EI
Date of Filing: April 1, 2004

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 2003, I was promoted to my current position, which includes supervision of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail electric tariff, and review of other regulatory filings submitted by the Company.

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 2003 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 2005?

A. An amount to be refunded of $631,135 was calculated which is reflected on Line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $631,135 to be refunded was calculated by taking the difference between the estimated January 2003 through December 2003 over-recovery of $209,163 as approved in Order No. PSC-03-1348-FOF-EI, dated November 25, 2003 and the actual over-recovery of $840,298 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 2003 through December 2003. 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 2003 through December 2003 with the estimated/actual O & M expenses included in the approved estimated true-up filed in conjunction with the November 2003 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 2003 through December 2003 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 2003 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 20 of Schedule 8A show the investment and associated costs related to capital projects, while page 18 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. 040007-EI
Date of Filing: August 4, 2004

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 2004 through December 2004 period to be refunded or collected in the period January 2005 through December 2005?

A. The estimated true-up for the current period is an under-recovery of $113,651 as shown on Schedule 1E. This is based on six months of actual data and six months of estimated data. This amount will be netted against the 2003 final true-up over-recovery amount of $394,531 (see Schedule 1A to my testimony filed April 1, 2004). The difference of $280,880 will be refunded to the customers during the January 2005 through December 2005 period. **The detailed** calculations supporting the estimated true-up for 2004 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 under-recovery of environmental costs for the period January 2004 through December 2004. **Schedule 3E of** my

exhibit is the calculation of the interest provision on the under-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 2004 through December 2004 with the projected O & M expenses approved by the Commission in conjunction with the November 2003 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 2004 through December 2004 compares the estimated/actual carrying costs related to investment with the projected amount approved in conjunction with the November 2003

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 22 pages that provide the monthly calculations of recoverable costs associated with each 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 21 of Schedule 8E show the investment and associated costs related to capital projects, while page 22 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 2004 through December 31, 2004.

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. 040007-EI
Date of Filing: September 3, 2004

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 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 2005 through December 2005.

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 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 2005 through December 2005. 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 2005 through December 2005?

A. The total projected jurisdictional recoverable costs for the period January 2005 through December 2005 are $26,067,223 as shown on line 1c of Schedule 1P. This includes costs related to O & M activities of $3,872,303 and costs related to capital projects of $22,194,920 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 $25,804,909 for the period January 2005 through December 2005 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 $280,880 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 2001 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 $21,787,810 for

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JAVIER PORTUONDO

ON BEHALF OF

PROGRESS ENERGY FLORIDA, INC.

DOCKET NO. 040007-EI

April 1, 2004

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

**A.** My name is Javier Portuondo. 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 Service Company, LLC as Director of Regulatory Services - Florida.

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

**A.** Yes.

**Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida'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 for Commission review and approval, Progress Energy Florida's Actual True-up costs associated with Environmental Compliance activities for the period January 2003 through December 2003.

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

A. Yes. I am sponsoring Exhibit No. JP-1, which consists of 8 forms. Form 42-1A reflects the final true-up for the period January 2003 through December 2003. Form 42-2A consists of the final true-up calculation for the period. Form 42-3A consists of the calculation of the Interest Provision for the period. Form 42-4A reflects the calculation of variances between actual and estimated/actual costs for O&M activities. Form 42-5A presents a summary of actual monthly costs for the period of O&M activities. Form 42-6A reflects the calculation of variances between actual and estimated/actual costs for Capital Investment Projects. Form 42-7A presents a summary of actual monthly costs for the period for Capital Investment Projects. Form 42-8A, pages 1 through 4, consist of the calculation of depreciation expense and return on capital investment for each project that is being recovered through the ECRC.

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

A. Unless otherwise indicated, the actual data is taken from the books and records of PEF. The books and records are kept in the regular course of our business in

accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

**Q. What is the final true-up amount for which PEF is requesting for the period January 2003 through December 2003?**

A. PEF is requesting approval of an under-recovery amount of $9,871,507 for the calendar period ending December 31, 2003. This amount is shown on Form 42-1A, Line 4.

**Q. What is the net true-up amount PEF is requesting for the January 2003 through December 2003 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. PEF has calculated and is requesting approval of an over-recovery amount of $951,437 reflected on Form 42-1A, as the adjusted net true-up amount for the January 2003 through December 2003 period. This amount is the difference between the actual under-recovery amount of $9,871,507 and the actual/estimated under-recovery of $10,822,944, as approved in Order PSC-03-1348-FOF-EI, for the period of January 2003 through December 2003.

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

A. Yes, they are.

**Q. How did actual O&M expenditures for January 2003 through December 2003 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits?**

A. Form 42-4A shows that total O&M project costs were $801,147 or 5.2% lower than projected. Following are variance explanations for those O&M Projects with significant variances. Individual project variances are provided on Form 42-4A.

**1. Substation Environmental Investigation, Remediation, and Pollution Prevention (Project No. 1) - O&M:**

Project expenditures were $108,414 more than anticipated, or a 22.9% variance. This variance is due primarily to a $70,000 item that was accrued in December 2003 in error. This was found after the books were closed and reversed in January 2004. The additional $38,000 variance was due to PEF performing remediation activities at two substation sites that were not in the original projection. These remediations were performed in accordance with the new Florida Department of Environmental Protection clean up criteria.

**2. Pipeline Integrity Management Program (Project No. 3a) – O&M:**

No project expenditures for O&M occurred this year compared to a projection of $10,000 for reviewing and updating the integrity management program plan and risk assessments, causing a 100% variance. This task was postponed until 2004 as the leak detection implementation was not completed in 2003 as previously expected (see capital variance explanation below).

**Q. How did actual Capital expenditures for January 2003 through December 2003 compare with PEF's estimated/actual projections as presented in previous testimony and exhibits?**

A. Form 42-6A shows that total Capital Investment project costs were $17,501 or 56.3% lower than projected. Actual costs and variance by individual project are provided on Form 42-6A. Return on Capital Investment, Depreciation and Taxes for each project for the period are provided on Form 42-8A, pages 1 through 4. Following are variance explanations for those capital projects with significant variances.

1. **Pipeline Integrity Management - Bartow/Anclote Pipeline (Project No. 3b) – Capital:**

   Recoverable costs were $11,188, or 54.1% lower than expected. This variance was due to the project not being completed by the end of 2003 as planned. During the fall of 2003, several non-environmental pipeline projects were being worked during a pipeline outage. These projects took priority in order to assure restoration of fuel supply to the Anclote Units. It is anticipated that the Bartow/Anclote Pipeline Leak Detection system will be fully implemented by June 2004.

2. **Above Ground Tank Secondary Containment - Turner CT's (Project No. 4a) – Capital:**

   Recoverable costs were $2,835 or 50.1% lower than expected. This variance was due to project delays related to the product used to line the tank. The tank work is expected to be completed by the end of the third quarter of 2004.

**3. Above Ground Tank Secondary Containment - Crystal River 1 & 2 (Project No. 4c) – Capital:**

Recoverable costs expenditures were $2,851 or 77.3% lower than projected. Estimates obtained early in the budgeting process projected capital expenditures to fall in the $100,000 range. However, after further study, a less costly alternative was found that met the regulatory requirements, resulting in actual capital expenditures of only $33,000. This project was certified in February 2004.

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

**A.** Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JAVIER PORTUONDO

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 040007

AUGUST 4, 2004

**(REVISED SEPTEMBER 3, 2004)**

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

**A.** My name is Javier J. Portuondo. 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 Service Company, LLC as Director of Regulatory Services - Florida.

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

**A.** Yes.

**Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida'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, for Commission review and approval, Progress Energy Florida's Estimated/Actual True-up costs associated with Environmental Compliance activities for the period January 2004 through December 2004.

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

A. Yes. I am sponsoring revised Exhibit No. __ (JP-2), which consists of revised PSC Forms 42-1E through 42-8E. These forms provide a summary and detail of the Estimated/Actual True-up O&M and Capital Environmental costs for the period January 2004 through December 2004.

**Q. What is the Estimated/Actual True-up amount that PEF is requesting recovery for the period of January 2004 through December 2004?**

A. The Estimated/Actual True-up amount for 2004 is an under-recovery, including interest, of $19,027,266, as shown in revised Exhibit No. __ (JP-2), Form 42-1E, Line 4.

**Q. Please explain the calculation of the ECRC Estimated/Actual True-up amount you are requesting this Commission to approve.**

A. Revised Forms 42-2E and 42-3E show the calculation of the ECRC Estimated/Actual True-up amount for the period of January 2004 through December 2004.

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

A. Yes.

**Q. How do the Estimated/Actual project expenditures for January 2004 through December 2004 compare with original projections?**

A. As shown on revised Form 42-4E, total O&M project costs are projected to be $18,745,199 or 178% higher than originally projected. Total recoverable capital investments itemized on revised Form 42-6E, are projected to be $710,778 or 764% higher than originally projected. Below are variance explanations for those O&M projects and Capital Investment Projects with significant variances. Individual project variances are provided on revised Forms 42-4E and 42-6E. Return on Capital Investment, Depreciation and Taxes for each project for the Estimated/Actual period are provided on revised Form 42-8E, pages 1 through 5.

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

Project expenditures are estimated to be $432,669 or 57% lower than previously projected. The original projection assumed remediation of 52 substations. The new projection is based on remediation of 9 substations. These projects have been delayed due to the longer time period than planned to obtain the required FDEP approval of the Substation Inspection Plan and the Substation Assessment and Remedial Action Plan. This project is discussed further in Kent D. Hedrick's testimony.

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

Project expenditures are estimated to be $2,930,034 or 57% higher than previously projected. This variance is primarily due to an increase in the estimated number of sites requiring remediation. The Company identified an additional 364 single-phase sites requiring remediation. The average cost per 3-phase site also increased from the previously estimated $10,000 per site to the current estimate of $14,000 per site, primarily due to the higher skill level necessary to perform 3-phase remediation activities. This project is discussed further in Kent D. Hedrick's testimony.

3. **Pipeline Integrity Management (Project #3a) – O&M**

Project expenditures are estimated to be $745,000 or 304% higher than previously projected. This variance is primarily due to more current estimates of the costs associated with required preventative measures, based on the results of pipeline inspections. PEF originally projected a total of $215,000 in O&M costs for the baseline integrity assessment of the Bartow/Anclote pipeline. Based on actual costs incurred to date and contractor bids for the remaining work, the estimated project costs have escalated by $75,000. Another $140,000 of this increase is attributable to costs associated with a new position devoted to management and oversight of the PIM program. **Further, in accordance with the PIM Plan, the** Company has identified unanticipated O&M project costs of approximately $550,000. These projects are necessary in order to provide protection against potential threats to pipeline integrity in accordance with the PIM regulations and the company's PIM Plan. These projects are discussed further in the testimony of Patricia Q. West.

**4. Pipeline Integrity Management – Bartow/Anclote Pipeline (Project #3b) – Capital**

Project expenditures are estimated to be $692,706 higher than previously forecasted. This is primarily attributable to $525,940 of expenses that were erroneously charged to non-recoverable O&M and should have been charged to recoverable capital and additional costs of $211,060 for the Bartow/Anclote Pipeline leak detection system to reduce risk in accordance

with the PIM Plan. These projects are further discussed in the testimony of Patricia Q. West's testimony.

**5. SO2 Emissions Allowances (Project #5) – O&M**

Project expenditures are estimated to be $15,502,833 or 352% higher than originally projected. This variance is driven by increases in projected tons of SO2 emissions and by higher market prices for allowances. The price variance is due in part to increased demand in the marketplace due to uncertainty associated with pending legislation on the Clean Air Interstate Ruling. The price of allowances increased from the previously projected average price of $160 per ton to the current projected average price of $400 - $600 per ton. The increase in projected tons is driven by higher natural gas prices which have resulted in more residual oil in the 2004 projected generation plan.

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

**A.** Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

**JAVIER PORTUONDO**

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 040007-EI

SEPTEMBER 3, 2004

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

**A.** My name is Javier J. Portuondo. 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 Service Company, LLC as Director of Regulatory Services - Florida.

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

**A.** Yes.

**Q. Have you previously filed testimony before this Commission in connection with Progress Energy Florida'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, for Commission review and approval, Progress Energy Florida's calculation of the revenue requirements and its Environmental Cost Recovery (ECRC) factors for application on customer billings during the period January 2005 through December 2005. My testimony addresses the capital and operating and maintenance ("O&M") expenses associated with PEF's environmental compliance activities for the year 2005.

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

A. Yes. I am sponsoring Exhibit No. __ (JP-3), which consists of PSC Forms 42-1P through 42-7P. These forms provide a summary and detail of the projected O&M and capital environmental cost recovery factors for the period January 2005 through December 2005.

**Q. What is the total true-up to be applied in the period January 2005 through December 2005?**

A. The total true-up applicable for this period is an under-recovery of $18,075,829. This consists of the final true-up over-recovery of $951,437 for the period from January 2003 through December 2003 and an estimated true-up under-recovery of $19,027,266 for the current period of January 2004 through December 2004.

The detailed calculation supporting the estimated true-up was provided on Forms 42-1E through 42-8E of Revised Exhibit No. __ (JP-2) filed with the Commission on September 3, 2004.

**Q. Are all the costs listed in Forms 42-1P through 42-7P attributable to Environmental Compliance projects previously approved by the Commission?**

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

The $SO_2$ Emissions Allowances (No. 5) were moved to the ECRC Docket from Docket 030001 beginning January 1, 2004 at the request of Staff to be comparative with the other Florida IOUs. Recovery of $SO_2$ Emission Allowances was previously approved in Order No. PSC-95-0450-FOF-EI. For 2005, we project $21,435,145 in SO2 Emission Allowance costs, based on a projected average market price of $351 per allowance.

The Pipeline Integrity Management Program (No. 3) and the Above Ground Tank Secondary Containment Program (No. 4) were previously approved in Order No. PSC-03-11348-FOF-EI.

On May 18, 2004, PEF filed a Petition for Approval of Environmental Cost Recovery for a new environmental program, the Phase II Cooling Water Intake

Program (No. 6). Discussion on this new program is included in the testimony of Patricia Q. West.

On May 25th, the Commission assigned Docket No. 040472-EI to the Petition. The Commission currently is scheduled to consider the Petition during the agenda conference on September 21, 2004. Consistent with the Petition, PEF has included projected O&M costs of $313,132 for the Phase II Cooling Water Intake Program for the period of January 2005 through December 2005.

**Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2005?**

A. Yes. Form 42-3P contained in Exhibit No. __ (JP-3), summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 6, shows the calculations of these costs that result in recoverable jurisdictional capital costs of $903,410.

**Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2005?**

A. Yes. Form 42-2P contained in Exhibit No. __ (JP-3), summarizes the recoverable O&M cost estimates for these projects in the amount of $29,601,039.

**Q. Have you prepared schedules providing the description and progress reports for all environmental compliance activities and projects?**

A. Yes. Form 42-5P, pages 1 through 6, contained in Exhibit No. __ (JP-3), provides each project description and progress, as well as the projected recoverable cost estimates.

**Q. What are the total projected jurisdictional costs for environmental compliance activities in the year 2005?**

A. The total jurisdictional capital and O&M costs to be recovered through the ECRC are calculated on Form 42-1P, contained in Exhibit No. __ (JP-3). These costs total $30,504,449.

**Q. Please describe how the proposed ECRC factors were developed.**

A. The ECRC factors were calculated as shown on Forms 42-6P and 42-7P contained in Exhibit No. __ (JP-3). 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 calculated by determining the percentage each rate class contributes to total kilowatt-hour sales and then adjusted for losses for each rate class. This information was obtained from Progress Energy Florida's July 2003 load research study. Form 42-7P presents the calculation of the proposed ECRC billing factors by rate class.

**Q. What are Progress Energy Florida's proposed 2005 ECRC billing factors by the various rate classes and delivery voltages?**

A. The computation of Progress Energy Florida's proposed ECRC factors for customer billings in 2005 is shown on Form 42-7P, contained in Exhibit No. __ (JP-3). In summary, these factors are as follows:

| Rate Class | ECRC Factor |
|---|---|
| Residential | 0.127 cents/kWh |
| General Service Non-Demand | |
| @ Secondary Voltage | 0.124 cents/kWh |
| @ Primary Voltage | 0.123 cents/kWh |
| @ Transmission Voltage | 0.122 cents/kWh |
| General Service 100% Load Factor | 0.103 cents/kWh |
| General Service Demand | |
| @ Secondary Voltage | 0.115 cents/kWh |
| @ Primary Voltage | 0.114 cents/kWh |
| @ Transmission Voltage | 0.113 cents/kWh |
| Curtailable | |
| @ Secondary Voltage | 0.125 cents/kWh |
| @ Primary Voltage | 0.124 cents/kWh |
| Interruptible | |
| @ Secondary Voltage | 0.106 cents/kWh |
| @ Primary Voltage | 0.105 cents/kWh |
| @ Transmission Voltage | 0.104 cents/kWh |
| Lighting | 0.115 cents/kWh |

**Q. When is Progress Energy Florida requesting that the proposed ECRC billing factors be made effective?**

A. PEF is requesting that its proposed ECRC billing factors be made effective with the first bill group for January 2005 and continuing through the last bill group for December 2005.

**Q. Please summarize your testimony.**

A. My testimony supports the approval of an average environmental billing factor of 0.121 cents per kWh which includes projected capital and O&M revenue requirements of $30,504,449 associated with a total of 6 environmental projects and a true-up under-recovery provision of $18,075,829. My testimony also demonstrates that the projected environmental expenditures for 2005 are appropriate for recovery through the ECRC.

**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. 040007-EI

AUGUST 4, 2004

**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 Services and Technical Assessment.

**Q. What is the scope of your duties?**

A. Currently, my responsibilities include management of the environmental compliance functions and activities 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 Services 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. No. My responsibilities have been expanded and now include environmental technical assessment for PEF.

**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 2004 through December 2004.

**Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Substation System Program for the period January 2004 to December 2004 (Project #1).**

A. Project expenditures for the Substation System Program are estimated to be $432,669 lower than originally projected. This is due to the reduced scope of work associated with the remediation activities in substations. The original projection was based on remediation of 52 substation sites in 2004. The new projection is based on remediation of 9 substation sites in 2004. A reduction in the number of substation sites is a result of a longer time period than planned to obtain required FDEP approval on the Substation Inspection Plan and the Substation Assessment and Remedial Action Plan. This additional time delayed the anticipated start date for substation remediation activities from the first quarter, 2004 until the current anticipated start date of the fourth quarter, 2004.

**Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Distribution System Program for the period January 2004 to December 2004 (Project #2).**

A. Project expenditures for the Distribution System Program are estimated to be $2,930,034 higher than originally projected. This variance is due to increased cost estimates for the associated investigation and remediation activities. As noted in the original projection testimony (*see* Direct Testimony of Kent D. Hedrick filed on behalf of PEF in Docket No. 030007-EI on September 8, 2003) a placeholder unit remediation cost of $10,000 per site on average was used for

3-phase sites, to develop the original projection. This was necessary because PEF was just beginning the remediation activities at 3-phase sites and the unit cost was difficult to estimate. A revised unit cost of $14,000 per 3-phase site on average is typical of the actual unit costs incurred to date resulting in higher than projected remediation activity cost. In addition, the number of single-phase sites targeted for remediation has been increased. An additional estimated 364 single-phase sites have been targeted for remediation activities during the period July 2004 through December 2004 at an estimated unit cost of $8,500 per site on average.

**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. 040007-EI

SEPTEMBER 3, 2004

**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 Services & 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. What is the purpose of your testimony?**

A. The Commission approved PEF's Substation and Distribution System Investigation, Remediation and Pollution Prevention Programs in Order No.

PSC-02-1735-FOF-EI. This testimony provides estimates of the costs that will be incurred for these programs in the year 2005.

**Q. What costs do you expect to incur in 2005 in connection with the Substation System Investigation, Remediation and Pollution Prevention Program (Project #1)?**

A. For 2005, we estimate Progress Energy will incur total O&M expenditures of $1,149,748 for the Substation System Investigation, Remediation and Pollution Prevention Program. This amount includes estimated costs for remediation activities at 66 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 will solicit competitive bids for the remediation activities necessary to comply with DEP criteria to ensure the level of expenditures is reasonable and prudent.

**Q. What costs do you expect to incur in 2005 in connection with the Distribution System Investigation, Remediation and Pollution Prevention Program (Project #2)?**

A. For 2005, we estimate total O&M expenditures of $7,354,748 for the Distribution System Investigation, Remediation and Pollution Prevention

Program to perform remediation activities at 784 sites. This estimate assumes 114 3-phase transformer sites at an average cost of $14,000 per site and 670 single-phase transformer sites at an average cost of $8,500 per site. The estimated per site costs are based on actual incurred 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 contractor to reduce fees for remediation activities and improve process efficiency.

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

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL DIRECT TESTIMONY OF

**KENT D. HEDRICK**

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 040007-EI

**OCTOBER 25, 2004**

**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 (PEF or "Company") as Manager of Environmental Services & Technical Assessment.

**Q. What is the scope of your duties?**

A. Currently, my responsibilities include management of the environmental compliance functions and activities for PEF.

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

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A. Yes, I have.

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

A. This testimony addresses Issue 10B of Staff's Prehearing Statement, which questions whether there should be an adjustment for broken water main costs of $8,748 that were charged to an ECRC approved Distribution System Investigation, Remediation and Pollution Prevention Program ("Distribution Remediation Program") in PEF's final true-up for 2003.

**Q. What were the circumstances that led to the $8,748 expenditure for broken water main costs referenced in Issue 10B of Staff's prehearing statement?**

A. In August, 2003, the Company's remediation contractor began performing remediation activities in Holiday, Florida, as part of the Company's approved Distribution Remediation Program. During the course of the remediation work, the removal of contaminated soil caused a previously unidentified water main to fail and to begin leaking water. As a result, the Company engaged a plumbing company to repair the broken water main at a cost of $8,748. The required remediation activity could not continue until the water main was repaired.

**Q. Why did the Company charge the $8,738 expenditure to the Environmental Cost Recovery Clause?**

A. We charged the expenditure to the Environmental Cost Recovery Clause because it was incurred as the direct result of environmental compliance

activities undertaken as part of a Commission-approved program. Moreover, the expenditure would not have been incurred but for such environmental compliance activities.

**Q. What, if any, steps does the Company take to identify water mains before undertaking remediation activities at distribution sites?**

The Company (or its remediation contractor) uses the Sunshine State One-Call of Florida, Inc. ("Sunshine State System" or "System"), to identify water mains and other underground facilities before undertaking remediation or other activities involving excavation. In rare instances, we also have engaged a third party contractor to perform specialized investigations at sites where there were visible indications that underground facilities, such as propane lines, may be present in the excavation area. The contractor uses specialized equipment, such as ground penetrating radar, which is not readily available to PEF or its remediation contractors.

**Q. What is the Sunshine State System?**

A. The Sunshine System was created under Chapter 556, F. S., to provide a free-access notification service for the identification of buried lines including electric lines, water mains, gas lines and other underground facilities. Section 556.104, F.S., requires any person who furnishes or transports materials or services by means of an underground facility in Florida to participate as a member operator of the system, except that small cities as defined in section, 120.52, F.S., may

elect not to participate in the system. Upon notification by an "excavator," the system notifies member operators who are required to identify all of their lines within the defined area of the excavation.

**Q. Why was the Company's remediation contractor unaware of the water main at issue?**

A. Because there were no visible signs or other indications of underground facilities at the site, the remediation contractor relied on the Sunshine State System. The contractor properly notified the System in advance of the remediation activities. The System did not identify and any underground facilities in the excavation area. I have since been informed that the water main belonged to a private entity that was not a member operator of the system.

**Q. Was Geoview or any other specialized contractor called in to inspect the site using the type of specialized equipment that you previously discussed?**

A. No specialized contractors were called in because there were no visible signs or other indications that underground facilities may have been at the site.

**Q. Have any other water mains or underground facilities have been damaged as a result of remediation activities conducted as part of the Distribution Remediation Program?**

A. No. As indicated in Form 42- 5P of Exhibit No. ___ (JP-3) attached to my testimony of September 3, 2004, PEF conducted remediation at 1,613

distribution sites in 2003. Of those remediations, the one discussed above is the only instance in which an underground facility was damaged.

**Q. How much would it cost to hire contractors to conduct such specialized inspections at each site where remediation activity is conducted as part of the Distribution Remediation Program?**

A. Such inspections cost approximately $500 per site. As stated in my pre-filed testimony of September 3, 2004, we expect to conduct remediation activities at 784 sites in 2005. Thus, if Progress Energy were required to hire contractors to conduct specialized inspections at each site, the Company would incur additional costs of approximately $392,000 in 2005 alone.

**Q. In your opinion, when is it prudent for PEF to contract for specialized investigations at remediation sites rather than rely on the Sunshine State System?**

Given the vast number of remediations that we have conducted over the past two years and the fact that the Sunshine State System only failed to identify one underground facility during that time period, I do not believe it would be prudent to incur the costs of conducting specialized investigations at every site targeted for remediation. In my opinion, it is only prudent to incur such costs in the rare instances where there is some visible indication or other circumstances suggesting that underground facilities may be present at a remediation site.

**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. 040007-EI

AUGUST 4, 2004

**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. ("Progress Energy" 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. 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. 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 ("PIM") Program for the period January 2004 through December 2004.

I will also explain the projected expenditures associated with PEF's Section 316(b) Cooling Water Intake Program for the remainder of 2004. PEF petitioned the Commission for approval of cost recovery for the Section 316(b) Cooling Water Intake Program on May 18, 2004. *See* Docket No. 040472.

**Q. Please explain the projected variance in O&M costs associated with the Pipeline Integrity Management ("PIM") Program (Project #3a).**

A. O&M costs for the PIM Program are projected to be $745,000 higher than originally projected. This variance is attributable to four factors. First, PEF originally projected a total of $215,000 in O&M costs for the PIM program. This included $150,000 for performing the baseline integrity assessment on the Bartow/Anclote pipeline segment, $50,000 for initiating the baseline assessment of the Bartow above-ground piping segment, and $15,000 for reviewing and

evaluating the results. Based on costs incurred to date and contractor bids for the remaining work, PEF now projects the costs of these activities for 2004 to be $290,000, resulting in a projected year-end variance of $75,000.

Second, PEF originally projected $20,000 in 2004 O&M costs to support the leak detection system. Because the work is being performed as part of a capital project, PEF has reclassified these expenses as capital costs, resulting in a negative variance of ($20,000) in O&M costs.

Third, due to increased workload associated with the PIM program, PEF created a new position solely devoted to oversight of the PIM program, resulting in a variance of approximately $140,000 in O&M costs.

Finally, in accordance with the PIM Plan, PEF's risk assessments have identified unanticipated O&M projects that need to be undertaken to reduce risks to pipeline integrity and security. For the remainder of 2004, PEF expects to incur $250,000 in O&M costs for various remedial, preventative, and mitigative actions along the pipeline. In addition, PEF projects $300,000 in O&M costs to lower a segment of the Bartow-Anclote pipeline below Alligator Creek to ensure adequate coverage where water flow and meandering have exposed the pipeline. The county regularly cleans vegetation from the creek with large equipment to maintain flow, creating a high probability for damage to the pipeline unless the pipeline is lowered. This measure is necessary to comply with the PIM regulations (49 CFR Part 195) and PEF's PIM Plan, which require the company to evaluate potential threats to pipeline integrity, like third party damage, and to take preventative measures to provide enhanced protection.

**Q. Please explain the projected variance in capital costs for the Pipeline Integrity Management ("PIM") Program (Project #3b).**

A. Capital costs for the PIM Program are projected to be $692,706 higher than originally projected. This variance is attributable to several factors. First, PEF originally projected that work on the leak detection system for the Bartow/Anclote pipeline would be completed in 2003. However, the project was not completed on schedule. Year-to-date, PEF had a reclass of costs from the prior period (discussed in Mr. Portuondo's testimony) and has incurred $131,060 in capital costs for the project and we anticipate incurring an additional $20,000 by year's end (as discussed above this expense was originally classified as O&M). Thus, we project a variance of $151,060 in capital costs for the leak detection system.

Second, PEF projects $60,000 in previously unanticipated capital costs to construct a protection system around a section of the pipeline at Alderman Road in order to reduce risks to pipeline integrity. This section of the pipeline is routed along a sand embankment that is used by four wheel drive vehicles for recreational purposes. This activity has left the pipeline exposed and vulnerable to further damage unless measures are taken to preclude public access. This is necessary to comply with the PIM regulations (49 CFR Part 195) and PEF's PIM Plan which, as discussed above, require the company to take preventative measures to provide protection against potential threats to pipeline integrity, including third party damage.

**Q. What costs do you expect to incur in 2004 in connection with Section 316(b) Cooling Water Intake Program?**

A. On May 18, 2004, PEF petitioned the Commission for approval of cost recovery for a new environmental program required to comply with new regulations adopted by the U.S. Environmental Protection Agency under Section 316(b) of the Clean Water Act. For the remainder of 2004, we estimate total O&M expenditures of $50,000 to $100,000 for the development of a Proposal for Information Collection required by the new regulations. However, those projected costs do not exceed the $287,500 in environmental study costs that PEF included in the MFRs filed in Docket No. 000824-EI. Thus, consistent with Commission's offsetting policy discussed in PEF's petition, PEF does not project any recoverable costs for this program in 2004.

**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. 040007-EI

SEPTEMBER 3, 2004

**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. ("Progress Energy" 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. Have you previously filed testimony before this Commission in connection with Progress Energy Florida's Environmental Cost Recover 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?**

In 2003 the Commission determined that the costs of two new environmental programs are eligible for recovery through the Environmental Cost Recovery Clause ("ECRC"). Those two projects are:

- Pipeline Integrity Management Program (Project 3)
- Aboveground Storage Tank Secondary Containment Projects (Project 4).

In May 2004, the Company filed a petition in Docket No. 040472-EI requesting approval of a new environmental program for cost recovery through the ECRC. That program, entitled the Phase II Cooling Water Intake Program (Project 6), is being implemented in order to comply with new requirements established by the U.S. Environmental Protection Agency ("EPA") in new rules to be codified 40 CFR 125 Subpart J, and associated amendments to existing rules.

This testimony provides estimates of the costs that will be incurred for each of these programs in the year 2005.

**Q. What costs do you expect to incur in 2005 in connection with the Pipeline Integrity Management Program (Project 3a)?**

A. For 2005, we estimate that Progress Energy will incur a total $1,056,000 in O&M expenditures to comply with the Pipeline Integrity Management ("PIM") regulations (49 CFR Part 195) and the Company's PIM Plan. This figure includes the costs of: analyzing data generated when performing the required baseline integrity assessment of the pipeline, and performing any necessary corrective actions on the pipeline ($446,000); continued management and implementation of the required integrity management program ($250,000); providing for projects to ensure pipeline protection for areas found to have inadequate cover or other risk reduction measures ($250,000); and implementation of protective measures necessitated by the Florida Department of Transportation's planned alteration of Highway 19 ($110,000).

**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 2005 in connection with the Above Ground Storage Tank Secondary Containment Program (Project 4d)?**

A. Progress Energy is currently estimating $1,500,000 in capital expenditures in 2005. These costs are for the double-bottoming of two storage tanks (DEP ID Nos. 17 and 18) at the Intercession City Combustion Turbine site in accordance

with Rule 62-761.510(3)(d), F.A.C., Table AST U(1), and the double-walling of pipe in contact with the soil in accordance with Rule 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 Above Ground 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 2005 in connection with the Phase II Cooling Water Intake Program (Project 6)?**

**A.** Progress Energy is currently estimating total O&M expenditures of $600,632 in connection with the Phase II Cooling Water Intake Program in 2005. These costs include approximately $65,000 for the development of the Company's Proposal for Information Collection in accordance with 40 C.F.R. § 125.95(b)(1), and approximately $535,000 for environmental studies to be performed as part of the Comprehensive Demonstration Study for one site in accordance with 40 C.F.R. § 125.95(b)(3). Based on guidance recently released by EPA, Progress also may need to perform or initiate environmental studies at one or more additional sites in 2005 to meet EPA's interpretation of the

timeframes for submitting permit application materials under 40 C.F.R. § 125.95(a)(2).

In accordance with the Commission's off-setting policy discussed in Progress' petition for approval of this new Program, Progress only seeks to recover those annual costs of environmental studies associated with the new Program in excess of the amount included in the MFRs that Progress Energy filed in Docket No. 000824-EI (i.e., $287,500) reduced by the amount actually spent on environmental studies during the relevant ECRC recovery period. Progress does not anticipate any expenditures on non-ECRC environmental studies in 2005. Thus, the company projects total recoverable costs for the new Program to be $313,132 for 2005 (i.e., $600,632 - $287,500 = $313,132).

**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. 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 ECCR dockets since 1993. I have also submitted testimony in the ECRC dockets 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 thereof associated with the environmental compliance activities for the January 2003 through December 2003 period.

**Q.** Do you wish to sponsor 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 2002 through December 2002 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 20, consists of the calculation of depreciation expenses and return on capital investment for each project that is being recovered through the ECRC, and page 21 calculates the costs associated with maintaining an $SO_2$ allowance inventory.

**Q.** What is the source of the data which you will present by way of 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 which Tampa Electric is requesting for the January 2003 through December 2003 period?

**A.** Tampa Electric has calculated and is requesting approval of an under-recovery of $424,154 as the actual true-up amount for the January 2003 through December 2003 period.

**Q.** What is the adjusted net true-up amount which Tampa Electric is requesting for the January 2003 through December 2003 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 under-recovery of $260,351 reflected on Form 42-1A, as the adjusted net true-up amount for the January 2003 through December 2003 period. This adjusted net true-up

amount is the difference between the actual under-recovery and the actual/estimated under-recovery for the January 2003 through December 2003 period as depicted on Form 42-1A. The actual true-up amount for the January 2003 through December 2003 period is an under-recovery of $424,154 as compared to the $163,803 actual/estimated under-recovery amount approved in FPSC Order No. PSC-03-1348-FOF-EI dated November 25, 2003.

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

**A.** Yes they are.

**Q.** How did actual expenditures for the January 2003 through December 2003 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 $7,895,018 or 0.9 percent greater than actual/estimated projections. Form 42-6A shows the total capital investment costs were $21,877,688 or 0.1 percent greater than actual/estimated projections. O&M and capital

investment projects with material variances from the 2003 Actual/Estimated True-Up filing are explained below.

**O&M Project Variances**

- **$SO_2$ Emission Allowances:** The $SO_2$ Emission Allowances project variance was $174,549 or 44.8 percent greater than projected due to higher payments to cogenerators and greater allowance costs than projected.
- **Big Bend $NO_x$ Emissions Reduction:** The Big Bend $NO_x$ Emissions Reduction project variance was $48,010 or 19.2 percent less than projected due to a postponement of the fineness testing on Big Bend Unit 4 until 2004.
- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study was $3,608 or 17.7 percent greater than projected due to the Florida Department of Environmental Protection's request for additional data as the development of the plan of study for the project continues to be negotiated between the agency and the company.
- **Polk $NO_x$ Emissions Reduction:** The Polk $NO_x$ Emissions Reduction project variance was $7,465 or 45.5 percent less than projected due to the anticipated maintenance on the saturator and demineralized water systems not being required at the time of unit outage.
- **Bayside SCR Consumables:** The Bayside SCR Consumables

project variance was $46,658 or 70.4 percent less than projected due to unit operating hours being less than anticipated. Additionally, the unit continues to operate in a cleaner manner than designed. The newness of system required less ammonia than projected.

**Capital Investment Project Variances**

- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance was $25,297 or 29.7 percent less than projected due to a reduction in capital expenditures achieved through strong management of construction activities and costs.

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

**A.** Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 040007-EI
FILED: 08/04/04

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 2004 through December 2004 true-up amount to be refunded or recovered through the ECRC in the projection period January 2005 through December 2005. My testimony addresses the recovery of capital and operating and maintenance ("O&M") costs associated with environmental compliance activities for 2004, 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 2005.

**Q.** Have you prepared an exhibit that shows the determination of the recoverable environmental costs for the period January 2004 through December 2004?

**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 2005.

**Q.** What has Tampa Electric calculated as the estimated true-up for the current period to be applied in the January 2005 through December 2005 ECRC factors?

**A.** The estimated true-up applicable for the current period, January 2004 through December 2004, is an over-recovery of $7,329,011. 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 2004 factors?

**A.** Yes. On July 15, 2004, Tampa Electric filed a petition

for approval of cost recovery for four new environmental compliance programs - Big Bend Unit 4 Selective Catalytic Reduction ("SCR"), Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR. These programs have been assigned Docket No. 040750-EI. The Commission staff recommendation for this docket is due on September 9, 2004, and consideration of this recommendation is scheduled for Commission action at its September 21, 2004 Agenda Conference. The final order in this docket is scheduled to be issued October 11, 2004.

Tampa Electric is seeking recovery of capital costs for the Big Bend Units 1, 2 and 3 Pre-SCR programs in this estimated true-up filing for calendar year 2004. These capital costs are for the implementation of the programs and are shown on Form 42-8E, pages 17 through 19. O&M expenses for the programs should not occur until 2005 and will be addressed in the upcoming projection filing.

Concerning the Big Bend Unit 4 SCR program, project construction is scheduled to begin in 2004 and continue through mid-2007 with an estimated total expenditure of $65.4 million. Based on the Commission's previous ruling in Docket No. 980693-EI, the company will not seek recovery of these expenditures until mid-2007, the

expected in-service date for the project. At that time, the associated depreciation expense and allowance for funds used during construction for the program will be requested for ECRC recovery. Therefore, Form 42-8E, page 20 only provides projected expenditures associated with the implementation of the project; however, as can be seen from the form, no recovery of costs is being requested at this time.

**Q.** How did the actual/estimated project expenditures for January 2004 through December 2004 period compare with the company's original projection?

**A.** As shown on Form 42-4E, total O&M activities were $7,457,067 or 88.6 percent lower than projected costs. Total capital expenditures itemized on Form 42-6E, were $92,172 or 0.5 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 $240,324 or 10.9 percent lower than originally projected due to a decrease

in the cost of consumables, principally potable water and chemicals, from the original projection. Additionally, a change was made in the outage schedule which did not permit for originally planned maintenance to occur in 2004.

- **$SO_2$ Emission Allowances:** The $SO_2$ Emission Allowances project variance is estimated to be $7,387,985 lower than originally projected. The significant variance is due to the magnitude of unanticipated proceeds from the sale of allowances associated with Hookers Point Station which created a credit balance that was then applied to the allowances consumed. By selling the Hookers Point Station allowances in July 2004, Tampa Electric was able to take advantage of favorable pricing in the $SO_2$ allowance market and thereby pass the revenue from the large sale directly to customers as an offset to the otherwise projected allowance expenses for 2004.
- **Big Bend Unit 1 & 2 Flue Gas Desulfurization:** The Big Bend Unit 1 & 2 Flue Gas Desulfurization project variance is estimated to be $485,456 or 11.3 percent higher than originally projected due to an outage schedule change that allowed for a major inspection and subsequent maintenance on towers, inlet ducts, oxidation air headers, absorber pumps and structural steel replacement. This activity was not originally planned for 2004.

- **Big Bend $NO_x$ Emissions Reduction:** The Big Bend $NO_x$ Emissions Reduction project variance is estimated to be $44,966 or 8.3 percent lower than originally projected due to less testing and maintenance related to coal fineness.
- **NPDES Annual Surveillance Fees:** The NPDES Annual Surveillance Fees project is estimated to be $9,200 or 21.1 percent lower than originally projected due to the exemption for Hookers Point Station which is no longer in service.
- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance is estimated to be $97,474 or 39.0 percent lower than originally projected. The variance is due to minimal spending until the sampling plan for the study is approved by the Department of Environmental Protection which is expected to occur in the late third or early fourth quarter of 2004.
- **Polk $NO_x$ Emissions Reduction:** The Polk $NO_x$ Emissions Reduction project variance is estimated to be $9,599 or 29.3 percent lower than originally projected. The variance is due to a lower amount of maintenance to the reverse osmosis system and saturator than originally projected.
- **Bayside SCR Consumables:** The Bayside SCR Consumables project variance is estimated to be $173,459 or 71.4

percent lower than originally projected. This variance is due to a lower running rate for the units than originally projected. Additionally, the units are operating much cleaner than originally projected; therefore, a lower amount of ammonia is projected to be consumed.

**Capital Investment Project Variances**

- **Big Bend FGD Optimization and Utilization:** The Big Bend FGD Optimization and Utilization project variance is estimated to be $51,419 or 1.8 percent higher than the original projection due to a Commission field audit request to lower the plant-in-service amount just prior to the submission of the 2004 projection. However, upon further review at a later date by the company and the Commission field audit personnel, the plant-in-service amount was restored to its original amount thereby creating the current variance.
- **Big Bend $NO_x$ Emissions Reduction:** The Big Bend $NO_x$ Emissions Reduction project variance is estimated to be $15,337 or 2.5 percent higher than the original projection due to project costs coming in slightly higher than anticipated.
- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance is estimated

to be $67,142 or 7.3 percent lower than the original projection due to a change in maintenance outages from spring to fall of 2004.

- **Polk $NO_x$ Emissions Reduction:** The Polk $NO_x$ Emissions Reduction project variance is estimated to be $13,493 or 5.5 percent lower than the original projection due to a lower plant-in-service base for the calculation of the depreciation expense and return on average net investment than originally projected.
- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance is estimated to be $118,685 or 28.0 percent lower than the original projection due to the competitive bid process and overall project management that resulted in a reduction of actual expenditures from the projected amount.
- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance is estimated to be $11,354 due to the project not being filed at the time of the submission of the 2004 projection filing.
- **Big Bend Unit 2 Pre-SCR:** The Big Bend Unit 2 Pre-SCR project variance is estimated to be $16,325 due to the project not being filed at the time of the submission of the 2004 projection filing.
- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is estimated to be $12,713 due to the

project not being filed at the time of the submission of the 2004 projection filing.

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

**A.** Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 040007-EI
FILED: SEPTEMBER 3, 2004

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 "the 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 2005 through December 2005. 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 2005.

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

**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 2005.

**Q.** What has Tampa Electric calculated as the net true-up to be applied in the period January 2005 through December 2005?

**A.** The net true-up applicable for this period is an over-recovery of $7,068,660. This consists of the final true-up under-recovery of $260,351 for the period of January 2003 through December 2003 and an estimated true-up over-recovery of $7,329,011 for the current period of January 2004 through December 2004. The detailed calculation supporting the estimated net true-up was provided on Forms 42-1E through 42-8E of Exhibit No. ___ **(HTB-2)** filed with the Commission on August 4, 2004.

**Q.** Has Tampa Electric proposed any new environmental compliance projects for ECRC cost recovery for the period from January 2005 through December 2005?

**A.** Yes. On July 15, 2004, Tampa Electric filed a petition for approval of cost recovery for four new environmental compliance programs - Big Bend Unit 4 Selective Catalytic Reduction ("SCR"), Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR, which was assigned Docket No. 040750-EI. The Commission staff recommendation for this docket is due on September 9, 2004, and consideration of this recommendation is scheduled for Commission action at its September 21, 2004 Agenda Conference. The final order in this docket is scheduled to be issued October 11, 2004.

Tampa Electric is seeking recovery of capital and O&M expenditures for the Big Bend Units 1, 2 and 3 Pre-SCR programs in this projection filing. The capital costs for the implementation of the programs are shown on Form 42-4P, pages 17 through 19. The O&M expenses for these programs are shown on Form 42-2P.

Concerning the Big Bend Unit 4 SCR program, project construction is scheduled to begin in 2004 and continue through mid-2007 with an estimated total expenditure of $65.4 million. Based on the Commission's previous ruling in Docket No. 980693-EI, the company will not seek recovery of these expenditures until mid-2007, the

expected in-service date for the project. At that time, the associated depreciation expense and allowance for funds used during construction for the program will be requested for ECRC recovery. Therefore, Form 42-4P, page 20 only provides projected expenditures associated with the implementation of the project; however, as demonstrated on the form, no recovery of costs is being requested at this time.

**Q.** What are the existing capital projects included in the calculation of the ECRC factors for 2005?

**A.** Tampa Electric proposes to include for ECRC recovery the 16 previously approved capital projects and their projected costs in the calculation of the ECRC factors for 2005. These projects are Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration, Big Bend Units 1 and 2 Flue Gas Conditioning, Big Bend Unit 4 Continuous Emissions Monitors, Big Bend Unit 1 Classifier Replacement, Big Bend Unit 2 Classifier Replacement, Big Bend Units 1 and 2 FGD, Big Bend Section 114 Mercury Testing Platform, Big Bend FGD Optimization and Utilization, Big Bend Particulate Matter ("PM") Minimization and Monitoring, Big Bend $NO_x$ Emissions Reduction, Polk $NO_x$ Emissions Reduction, Big Bend Unit 4

SOFA, Big Bend Fuel Oil Tank No. 1 Upgrade, Big Bend Fuel Oil Tank No. 2 Upgrade, Phillips Tank No. 1 Upgrade, and Phillips Tank No. 4 Upgrade.

**Q.** Have you prepared schedules showing the calculation of the recoverable capital project costs for 2005?

**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 20, provides the calculations of the costs which result in recoverable jurisdictional capital costs of $18,249,961.

**Q.** What are the existing O&M projects included in the calculation of the ECRC factors for 2005?

**A.** Tampa Electric proposes to include for ECRC recovery the 11 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2005. These projects are Big Bend Unit 3 FGD Integration, Big Bend Units 1 and 2 Flue Gas Conditioning, Big Bend Units 1 and 2 FGD, Big Bend PM Minimization and Monitoring, Big Bend $NO_x$ Emissions Reduction, Polk $NO_x$ Emissions Reduction, Bayside SCR Consumables, Big Bend Unit 4 SOFA, $SO_2$ Emissions Allowances, NPDES Annual Surveillance Fees,

and the Gannon Thermal Discharge Study.

**Q.** Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2005?

**A.** Yes. Form 42-2P contained in Exhibit No. (HTB-3) summarizes the recoverable jurisdictional O&M costs for these projects which total $8,595,531 for 2005.

**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 24.

**Q.** What are the total projected jurisdictional costs for environmental compliance in the year 2005?

**A.** The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $26,845,492.

**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 kilowatt hour ("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 2005 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 2005 proposed ECRC billing factors are:

| **Rate Class** | **Factor (¢/kWh)** |
|---|---|
| Average Factor | 0.103 |
| RS, RST | 0.104 |
| GS, GST, TS | 0.104 |
| GSD, GSDT | 0.103 |

| | | |
|---|---|---|
| | GSLD, GSLDT, SBF | 0.102 |
| | IS1, IST1, SBI1 | |
| | IS3, IST3, SBI3 | 0.100 |
| | SL, OL | 0.101 |

**Q.** When does Tampa Electric propose to begin collection of these environmental cost recovery charges?

**A.** The environmental cost recovery charges will be effective concurrent with the first billing cycle for January 2005.

**Q.** Are the costs Tampa Electric is requesting for recovery through the ECRC for the period January 2005 through December 2005 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 factor of 0.103 cents per kWh which includes projected capital and O&M revenue requirements of $26,845,492 associated with a total of 24 environmental projects and a true-up over-recovery provision of $7,068,660. My testimony also explains that the projected environmental expenditures for 2005 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 "the 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 2005 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 four new environmental compliance programs to control nitrogen oxides ("$NO_x$") emissions: Big Bend Unit 4 Selective Catalytic Reduction ("SCR"), Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR. These compliance programs were submitted to the Commission for ECRC cost recovery approval on July 15, 2004 and assigned Docket No. 040750-EI.

**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 provide further reductions for sulfur dioxide ("$SO_2$"), particulate matter ("PM") and $NO_x$

emissions at Big Bend Station. The repowering of Gannon Station 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") at Big Bend Station. 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 performed to upgrade each scrubber at Big Bend and 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. There will be additional work required in 2009 and 2012 coincident with the elimination of the scrubber outage days.

Concerning PM emissions reduction, 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 BOP and BACT PM emission reduction projects will be completed in 2004 and there are no projects scheduled for 2005. 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.

The early $NO_x$ reduction activities are ongoing and will continue into 2005. 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.

**Q.** Please describe the Big Bend Early $NO_x$ Emissions Reduction program activities and provide the estimated O&M and capital expenditures for 2005.

**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 2005, Tampa Electric has identified the projects that will reduce $NO_x$ emissions as required under the Orders. These include performing the requisite maintenance on the previously approved $NO_x$ reduction projects, completion of the Department of Energy neural network sootblowing project and continuing the coal and air-flow monitoring and balancing projects, both on Big Bend Unit 2. These projects are expected to result in approximately $165,000 of capital expenditures and $484,000 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 2005.

**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. For 2004, the BOP and BACT projects included the installation and demonstration of a PM CEM system, the installation of flyash controls on Big Bend Units 2 and 3, thermal flow corrections on Big Bend Unit 3 and completion of the work on Big Bend Unit 1 slag vent fans. No new capital improvement projects are planned for 2005. 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 $1,050,000 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 and Big Bend Unit 4 Separated Over-fired Air ("SOFA").

**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 2005.

**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 2005, 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 $2,240,000 and $4,400,000, 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 maintenance.

**Q.** Please describe the Gannon Thermal Discharge Study program activities and provide the estimated O&M and capital expenditures for 2005.

**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. The FDEP is currently reviewing the sampling plan submitted by Tampa Electric. Approval is expected in late 2004 with commencement of the work immediately thereafter. For 2005, there will be no capital expenditures for this program; however, Tampa Electric anticipates O&M expenses will be approximately $500,000.

**Q.** Please describe the Bayside SCR Consumables program activities and provide the estimated capital and O&M expenditures for 2005.

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 2005, 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 $115,000.

Q. Please describe the Big Bend Unit 4 SOFA program activities and provide the O&M and capital expenditures for 2005?

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, will comply with the applicable provisions of the CD associated with this decision. The SOFA project was completed in 2004 and the annual O&M expense for 2005 is anticipated to be approximately $50,000.

**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. Attached as Exhibit A to Tampa Electric's July 15, 2004 petition for cost recovery to the Commission is a document entitled "The Big Bend Technology Assessment Study and $NO_x$ Compliance Plan" ("Study"), which contains the results of the evaluation. The Study evaluated the options of: 1) remaining coal-fired, 2) repowering the facility, or 3) shutting down

the station and replacing it with new generation. The results of the Study clearly indicate 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 option will require Tampa Electric to install SCR reduction technologies to meet future $NO_x$ emission rates as required by the Orders.

**Q.** Please describe the Big Bend Unit 4 SCR, Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR programs and provide estimated capital and O&M expenditures for 2005.

**A.** Tampa Electric's July 15, 2004 petition to the Commission seeks approval of recovery through the ECRC for the costs associated with the projects identified in the Study, namely, Big Bend Unit 4 SCR, Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR, as necessary to begin to cost-effectively meet the $NO_x$ emissions requirements of the Orders. The Big Bend Unit 4 SCR project encompasses the design, procurement, installation and annual O&M expenses associated with an SCR system for the unit. The Pre-SCR Big Bend Units 1

through 3 projects are cost-effective precursors to SCR systems. These Pre-SCR technologies include a neural network system, secondary air controls and windbox modifications for Big Bend Unit 1; secondary air controls and windbox modifications for Big Bend Unit 2; and a neural network system, secondary air controls, windbox modifications and primary coal/air flow controls for Big Bend Unit 3. The purpose of the Pre-SCR technologies on Big Bend Units 1 through 3 is to reduce inlet $NO_x$ concentrations to the SCR systems thereby mitigating overall SCR capital and O&M costs. The installation of these Pre-SCR technologies is accepted throughout the industry as the more prudent, cost-effective decision over simply installing larger SCR systems.

The 2005 projected costs for which Tampa Electric is seeking ECRC recovery are for the capital and O&M expenditures associated with the engineering, procurement, construction, start-up, tuning, operation and ongoing maintenance for three of the four programs. The 2005 projected capital and O&M expenditures for Big Bend Unit 1 Pre-SCR are $1,705,000 and $27,000, respectively. The 2005 projected capital and O&M expenditures for Big Bend Unit 2 Pre-SCR are $1,000,000 and $23,000, respectively. Finally, the 2005 projected capital and O&M expenditures

for Big Bend Unit 3 Pre-SCR are $2,135,000 and $66,000, respectively.

The 2005 projected capital expenditure for Big Bend Unit 4 SCR is $9,500,000. However, as previously stated in Tampa Electric witness Bryant's Prepared Direct Testimony in the 2004 ECRC Actual/Estimated True-Up filed August 3, 2004, the company will not seek recovery of the capital expenditures until mid-2007, the expected in-service date for the project. At that time, the associated depreciation expense and allowance for funds used during construction for the program will be requested for ECRC recovery.

**Q.** Please summarize your testimony.

**A.** Tampa Electric's settlement agreements with FDEP and EPA which 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 2005. Finally, my testimony identified other projects which are required for Tampa Electric to meet environmental requirements and I provided associated 2005 activities and projected expenditures.

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

**A.** Yes it does.

MS. STERN: And, finally, all the issues have been stipulated. The stipulations are shown on Pages 6 through 16 of the prehearing order, and staff recommends that the Commission approve the stipulations.

CHAIRMAN BAEZ: Commissioners, any questions on the stipulations? If there are none, we can entertain a motion.

COMMISSIONER DEASON: I move approval of stipulated Issues 1 through 8, and then the company-specific stipulated Issues 9A through 12F.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN BAEZ: Motion and a second. All those in favor, say aye. Aye.

(Unanimous affirmative vote.)

CHAIRMAN BAEZ: Thank you, Commissioners. And that concludes Docket 07.

(Proceeding adjourned.)

STATE OF FLORIDA )

CERTIFICATE OF REPORTER

COUNTY OF LEON )

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

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

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

DATED THIS 16th day of November, 2004

LINDA BOLES, RPR
FPSC Official Commission Reporter
(850) 413-6734

| Comprehensive Exhibit List for Entry into Hearing Record | | | |
|---|---|---|---|
| **Hearing I.D. #** | **Witness** | **I.D. # As Filed** | **Exhibit Description** |
| *Staff* | | | |
| 1 | | Exhibit List-Staff-1 | Comprehensive Stipulated Exhibit List |
| *Testimony Exhibit List* | | | |
| *Florida Power & Light* | | | |
| 2 | K.M. Dubin | KMD-1 | Forms 42-1A – 42-8A |
| 3 | K.M. Dubin | KMD-2 | Forms 42-1E – 42-8E |
| 4 | K.M. Dubin | KMD-3 | Forms 42-1P – 42-7P |
| 5 | R.R LaBauve | RRL-1 | Martin Unit 8 Power Plant Siting Application PA 89-27A, Final Order of Certification and Excerpt from Conditions of Certification – Section IV, Air |
| 6 | R.R. LaBauve | RRL-2 | Manatee Unit 3 Power Plant Siting Application PA 02-44, Final Order of Certification and Excerpt from Conditions of Certification – Section XXIII, Air |
| 7 | R.R. LaBauve | RRL-3 | Drawing of a typical SCR module. |
| *Progress* | | | |
| 8 | Javier Portuondo | JP-1 | Forms 42-1A – 42-8A |
| 9 | Javier Portuondo | JP-2 (revised 9/3/04) | Forms 42-1E – 42-8E |
| 10 | Javier Portuondo | JP-3 | Forms 42-1P – 42-7P |
| *Tampa Electric Company* | | | |
| 11 | Howard T. Bryant | HTB-1 | Forms 42-1A – 42-8A |
| 12 | Howard T. Bryant | HTB-2 | Forms 42-1E – 42-8E |
| 13 | Howard T. Bryant | HTB-3 | Forms 42-1P – 42-7P |
| *Gulf Power Company* | | | |
| 14 | J.O. Vick | JOV-1 (pages 10-26 withdrawn) | Correspondence; Program Documentation |
| 15 | T.A. Davis | TAD-1 | Forms 42-1A – 42-8A |
| 16 | T.A. Davis | TAD-2 | Forms 42-1E – 42-8E |

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI EXHIBIT NO. 1
COMPANY/ F.P.S.C. Staff
WITNESS. Comprehensive Stipulated Exhibit List
DATE 11-08-04

| Comprehensive Exhibit List for Entry into Hearing Record | | | |
|---|---|---|---|
| **Hearing I.D. #** | **Witness** | **I.D. # As Filed** | **Exhibit Description** |
| 17 | T.A. Davis | TAD-3 (revised 10/12/04 and 10/22/04) | Forms 42-1P – 42-7P |

# APPENDIX I

## ENVIRONMENTAL COST RECOVERY
## COMMISSION FORMS 42-1A THROUGH 42-8A

## JANUARY 2003 - DECEMBER 2003
## FINAL TRUE-UP

KMD-1
DOCKET NO. 040007-EI
EXHIBIT_____
PAGES 1-41

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040007-EI EXHIBIT NO. 2
COMPANY/ FP+L
WITNESS: K.M. Dubin (KMD-1)
DATE 11-08-04

**Florida Power & Light Company**
**Environmental Cost Recovery Clause**
**Calculation of the Final True-up for the Period**
**January through December 2003**

| Line No. | | | | |
|---|---|---|---|---|
| 1 | Over/(Under) Recovery for the Current Period (Form 42-2A Page 2 of 2, Line 5) | $923,822 | | |
| 2 | Interest Provision (Form 42-2A Page 2 of 2, Line 6) | ($29,012) | | |
| 3 | Total | | $894,810 | |
| 4 | Estimated/Actual Over/(Under) Recovery for the Same Period * | $879,032 | | |
| 5 | Interest Provision | (28,099) | | |
| 6 | Total | | $850,933 | |
| 7 | Net True-Up for the period | | | $43,877 |

* Per Order No. PSC-03-1348-FOF-EI issued November 25, 2003

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2003

| Line No. | | January | February | March | April | May | June |
|---|---|---|---|---|---|---|---|
| 1 | ECRC Revenues (net of Revenue Taxes) | $1,237,033 | $1,356,620 | $1,364,256 | $1,345,182 | $1,456,677 | $1,650,512 |
| 2 | True-up Provision (Order No. PSC-02-1735-FOF-EI) | (605,967) | (605,967) | (605,967) | (605,967) | (605,967) | (605,967) |
| 3 | ECRC Revenues Applicable to Period (Lines 1 + 2) | 631,066 | 750,654 | 758,289 | 739,215 | 850,710 | 1,044,546 |
| 4 | Jurisdictional ECRC Costs | | | | | | |
| | a - O&M Activities (Form 42-5A, Line 9) | 137,881 | 150,469 | 179,769 | 180,280 | 151,390 | 265,177 |
| | b - Capital Investment Projects (Form 42-7A, Line 9) | 462,442 | 460,803 | 459,134 | 462,008 | 457,789 | 454,452 |
| | c - Total Jurisdictional ECRC Costs | 600,323 | 611,272 | 638,903 | 642,288 | 609,179 | 719,629 |
| 5 | Over/(Under) Recovery (Line 3 - Line 4c) | 30,743 | 139,382 | 119,386 | 96,927 | 241,531 | 324,917 |
| 6 | Interest Provision (Form 42-3A, Line 10) | (7,198) | (6,367) | (5,402) | (4,569) | (3,856) | (2,735) |
| 7 | Est/Act True-Up for 2002 | (7,271,601) | (6,642,089) | (5,903,108) | (5,183,157) | (4,484,832) | (3,641,190) |
| | a - Deferred True-Up from 2001 | 205,349 | 205,349 | 205,349 | 205,349 | 205,349 | 205,349 |
| 8 | True-Up Collected /(Refunded) (See Line 2) | 605,967 | 605,967 | 605,967 | 605,967 | 605,967 | 605,967 |
| 9 | End of Period True-Up (Lines 5+6+7+7a+8) | (6,436,740) | (5,697,759) | (4,977,808) | (4,279,483) | (3,435,841) | (2,507,693) |
| 10 | Adjustments to Period Total True-Up Including Interest | | | | | | |
| 11 | End of Period Total Net True-Up (Lines 9+10) | ($6,436,740) | ($5,697,759) | ($4,977,808) | ($4,279,463) | ($3,435,841) | ($2,507,693) |

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2003

| Line No. | | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|
| 1 | ECRC Revenues (net of Revenue Taxes) | $1,708,183 | $1,676,749 | $1,703,625 | $1,606,876 | $1,473,092 | $1,399,922 | $17,978,728 |
| 2 | True-up Provision (Order No. PSC-02-1735-FOF-EI) | (605,967) | (605,967) | (605,967) | (605,967) | (605,967) | (605,967) | (7,271,601) |
| 3 | ECRC Revenues Applicable to Period (Lines 1 + 2) | 1,102,216 | 1,070,782 | 1,097,658 | 1,000,910 | 867,125 | 793,955 | 10,707,127 |
| 4 | Jurisdictional ECRC Costs | | | | | | | |
| | a - O&M Activities (Form 42-5A, Line 9) | 171,222 | 169,295 | 209,745 | 99,288 | 173,841 | 2,182,649 | 4,071,006 |
| | b - Capital Investment Projects (Form 42-7A, Line 9) | 687,182 | 453,316 | 450,808 | 449,076 | 453,842 | 461,447 | 5,712,299 |
| | c - Total Jurisdictional ECRC Costs | 858,404 | 622,611 | 660,553 | 548,364 | 627,683 | 2,644,096 | 9,783,305 |
| 5 | Over/(Under) Recovery (Line 3 - Line 4c) | 243,812 | 448,171 | 437,105 | 452,546 | 239,442 | (1,850,141) | 923,822 |
| 6 | Interest Provision (Form 42-3A, Line 10) | (1,779) | (996) | (75) | 849 | 1,639 | 1,477 | (29,012) |
| 7 | Est/Act True-Up for 2002 | (2,713,042) | (1,865,042) | (811,900) | 231,097 | 1,290,458 | 2,137,506 | (7,271,601) |
| | a - Deferred True-Up from 2001 | 205,349 | 205,349 | 205,349 | 205,349 | 205,349 | 205,349 | 205,349 |
| 8 | True-Up Collected /(Refunded) (See Line 2) | 605,967 | 605,967 | 605,967 | 605,967 | 605,967 | 605,967 | 7,271,601 |
| 9 | End of Period True-Up (Lines 5+6+7+7a+8) | (1,659,693) | (606,551) | 436,446 | 1,495,807 | 2,342,855 | 1,100,159 | 1,100,159 |
| 10 | Adjustments to Period Total True-Up Including Interest | | | | | | | |
| 11 | End of Period Total Net True-Up (Lines 9+10) | ($1,659,693) | ($606,551) | $436,446 | $1,495,807 | $2,342,855 | $1,100,159 | $1,100,159 |

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2003

Interest Provision (in Dollars)

| Line No. | | January | February | March | April | May | June |
|---|---|---|---|---|---|---|---|
| 1 | Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10) | ($7,066,252) | ($6,436,740) | ($5,697,759) | ($4,977,808) | ($4,279,483) | ($3,435,841) |
| 2 | Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8) | (6,429,542) | (5,691,392) | (4,972,406) | (4,274,914) | (3,431,985) | (2,504,958) |
| 3 | Total of Beginning & Ending True-Up (Lines 1 + 2) | ($13,495,794) | ($12,128,132) | ($10,670,165) | ($9,252,722) | ($7,711,468) | ($5,940,799) |
| 4 | Average True-Up Amount (Line 3 x 1/2) | ($6,747,897) | ($6,064,066) | ($5,335,083) | ($4,626,361) | ($3,855,734) | ($2,970,400) |
| 5 | Interest Rate (First Day of Reporting Month) | 1.29000% | 1.27000% | 1.25000% | 1.18000% | 1.19000% | 1.21000% |
| 6 | Interest Rate (First Day of Subsequent Month) | 1.27000% | 1.25000% | 1.18000% | 1.19000% | 1.21000% | 1.00000% |
| 7 | Total of Beginning & Ending Interest Rates (Lines 5 + 6) | 2.56000% | 2.52000% | 2.43000% | 2.37000% | 2.40000% | 2.21000% |
| 8 | Average Interest Rate (Line 7 x 1/2) | 1.28000% | 1.26000% | 1.21500% | 1.18500% | 1.20000% | 1.10500% |
| 9 | Monthly Average Interest Rate (Line 8 x 1/12) | 0.10667% | 0.10500% | 0.10125% | 0.09875% | 0.10000% | 0.09208% |
| 10 | Interest Provision for the Month (Line 4 x Line 9) | ($7,198) | ($8,367) | ($5,402) | ($4,569) | ($3,856) | ($2,735) |

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2003

Interest Provision (In Dollars)

| Line No. | | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|
| 1 | Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10) | ($2,507,693) | ($1,659,693) | ($606,551) | $436,446 | $1,495,807 | $2,342,855 | ($32,392,712) |
| 2 | Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8) | (1,657,914) | (605,555) | 436,521 | 1,494,958 | 2,341,216 | 1,098,681 | (24,197,290) |
| 3 | Total of Beginning & Ending True-Up (Lines 1 + 2) | ($4,165,607) | ($2,265,248) | ($170,030) | $1,931,404 | $3,837,023 | $3,441,536 | ($56,590,002) |
| 4 | Average True-Up Amount (Line 3 x 1/2) | ($2,082,804) | ($1,132,624) | ($85,015) | $965,702 | $1,918,512 | $1,720,768 | ($28,295,001) |
| 5 | Interest Rate (First Day of Reporting Month) | 1.00000% | 1.05000% | 1.06000% | 1.06000% | 1.05000% | 1.00000% | N/A |
| 6 | Interest Rate (First Day of Subsequent Month) | 1.05000% | 1.06000% | 1.06000% | 1.05000% | 1.00000% | 1.06000% | N/A |
| 7 | Total of Beginning & Ending Interest Rates (Lines 5 + 6) | 2.05000% | 2.11000% | 2.12000% | 2.11000% | 2.05000% | 2.06000% | N/A |
| 8 | Average Interest Rate (Line 7 x 1/2) | 1.02500% | 1.05500% | 1.06000% | 1.05500% | 1.02500% | 1.03000% | N/A |
| 9 | Monthly Average Interest Rate (Line 8 x 1/12) | 0.08542% | 0.08792% | 0.08833% | 0.08792% | 0.08542% | 0.08583% | N/A |
| 10 | Interest Provision for the Month (Line 4 x Line 9) | ($1,779) | ($996) | ($75) | $849 | $1,639 | $1,477 | ($29,012) |

Form 42-4A

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
**January 2003 - December 2003**

Variance Report of O&M Activities
(in Dollars)

| Line | | (1) Actual | (2) Estimated Actual | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | |
| 1 | Air Operating Permit Fees-O&M | $1,805,360 | $1,971,032 | ($165,672) | -8.4% |
| 3a | Continuous Emission Monitoring Systems-O&M | $526,519 | $636,975 | ($110,456) | -17.3% |
| 5a | Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M | $82,169 | $306,177 | ($224,008) | -73.2% |
| 8a | Oil Spill Cleanup/Response Equipment-O&M | $107,580 | $168,888 | ($61,308) | -36.3% |
| 13 | RCRA Corrective Action-O&M | $63,581 | $52,498 | $11,083 | 21.1% |
| 14 | NPDES Permit Fees-O&M | $142,543 | $123,543 | $19,000 | 15.4% |
| 17a | Disposal of Noncontainerized Liquid Waste-O&M | $367,698 | $229,138 | $138,560 | 60.5% |
| 19a | Substation Pollutant Discharge Prevention & Removal - Distribution - O&M | $1,228,656 | $1,000,300 | $228,356 | 22.8% |
| 19b | Substation Pollutant Discharge Prevention & Removal - Transmission - O&M | $452,922 | $677,900 | ($224,978) | -33.2% |
| 19c | Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates | ($560,232) | ($560,232) | $0 | 0.0% |
| 20 | Wastewater Discharge Elimination & Reuse | $29,696 | $32,611 | ($2,915) | -8.9% |
| N/A | Amortization of Gains on Sales of Emission Allowances | ($482,207) | ($430,354) | ($51,853) | 12.0% |
| 22 | Pipeline Integrity Management | $177,784 | $72,784 | $105,000 | 144.3% |
| 23 | Spill Prevention, Control & Countermeasures (SPCC) | $160,850 | $76,261 | $84,589 | 110.9% |
| 2 | Total O&M Activities | $4,102,919 | $4,357,521 | ($254,602) | -5.8% |
| 3 | Recoverable Costs Allocated to Energy | $2,338,243 | $2,606,278 | ($268,035) | -10.3% |
| 4a | Recoverable Costs Allocated to CP Demand | $816,136 | $1,031,059 | ($214,923) | -20.8% |
| 4b | Recoverable Costs Allocated to GCP Demand | $948,540 | $720,184 | $228,356 | 31.7% |

Notes:
Column(1) is the End of Period Totals on Form 42-5A
Column(2) is the approved projected amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
January 2003 - December 2003

O&M Activities
(in Dollars)

| Line | | Actual JAN | Actual FEB | Actual MAR | Actual APR | Actual MAY | Actual JUN | End 6-Month Sub-Total |
|---|---|---|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | | | | |
| 1 | Air Operating Permit Fees-O&M | $6,083 | ($128,145) | $6,083 | $ 6,083 | $ 6,083 | $ 12,865 | $ (90,948) |
| 3a | Continuous Emission Monitoring Systems-O&M | 8,639 | 121,232 | 24,307 | 9,480 | 35,196 | 34,605 | 233,459 |
| 4a | Clean Closure Equivalency-O&M | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5a | Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M | 0 | 15,000 | 236 | 5,950 | 27,779 | 2,800 | 51,765 |
| 8a | Oil Spill Cleanup/Response Equipment-O&M | 2,926 | 4,115 | 15,610 | 2,787 | 4,151 | 11,301 | 40,890 |
| 13 | RCRA Corrective Action-O&M | 2,070 | 24,025 | (26,061) | 1,471 | 962 | 31 | 2,498 |
| 14 | NPDES Permit Fees-O&M | 124,400 | 0 | 0 | 0 | (857) | 0 | 123,543 |
| 17a | Disposal of Noncontainerized Liquid Waste-O&M | 17,500 | 1,410 | 31,292 | 25,268 | 736 | 53,932 | 130,138 |
| 19a | Substation Pollutant Discharge Prevention & Removal - Distribution - O&M | 29,540 | 118,816 | 142,165 | 81,790 | 71,873 | 230,565 | 674,749 |
| 19b | Substation Pollutant Discharge Prevention & Removal - Transmission - O&M | 6,067 | 17,450 | 20,566 | 71,716 | 37,516 | 82,497 | 235,812 |
| 19c | Substation Pollutant Discharge Prevention & Removal - Costs included in Base Rates | (46,686) | (46,686) | (46,686) | (46,686) | (46,686) | (46,686) | (280,116) |
| 20 | Wastewater Discharge Elimination & Reuse | 0 | 0 | 0 | 0 | 0 | 22,611 | 22,611 |
| N/A | Amortization of Gains on Sales of Emission Allowances | (11,342) | (11,342) | (11,342) | (11,342) | (11,342) | (158,466) | (215,176) |
| 22 | Pipeline Integrity Management | 0 | 35,134 | 20,000 | 0 | 17,650 | 0 | 72,784 |
| 23 | Spill Prevention, Control & Countermeasures (SPCC) | 0 | 0 | 4,230 | 34,986 | 9,364 | 19,681 | 68,261 |
| 2 | Total of O&M Activities | $139,197 | $151,009 | $180,400 | $181,503 | $152,425 | $265,736 | $1,070,270 |
| 3 | Recoverable Costs Allocated to Energy | $22,477 | -$13,183 | $65,736 | $ 35,997 | $ 35,914 | $ (41,213) | $ 105,729 |
| 4a | Recoverable Costs Allocated to CP Demand | $110,523 | $68,719 | -$4,158 | $87,059 | $67,981 | $99,727 | $ 429,850 |
| 4b | Recoverable Costs Allocated to GCP Demand | $6,197 | $95,473 | $118,822 | $ 58,447 | $ 48,530 | $ 207,222 | $534,691 |
| 5 | Retail Energy Jurisdictional Factor | 98.97818% | 98.97818% | 98.97818% | 98.97818% | 98.97818% | 98.97818% | |
| 6a | Retail CP Demand Jurisdictional Factor | 99.01742% | 99.01742% | 99.01742% | 99.01742% | 99.01742% | 99.01742% | |
| 6b | Retail GCP Demand Jurisdictional Factor | 100.00000% | 100.00000% | 100.00000% | 100.00000% | 100.00000% | 100.00000% | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | $22,247 | -$13,049 | $65,065 | $35,629 | $35,547 | ($40,792) | $104,647 |
| 8a | Jurisdictional CP Demand Recoverable Costs (B) | $109,437 | $68,044 | -$4,118 | $86,204 | $67,313 | $98,747 | $425,627 |
| 8b | Jurisdictional GCP Demand Recoverable Costs (C) | $6,197 | $95,473 | $118,822 | $58,447 | $48,530 | $207,222 | $534,691 |
| 9 | Total Jurisdictional Recoverable Costs for O&M Activities | $137,881 | $150,468 | $179,769 | $ 180,280 | $ 151,390 | $ 265,177 | $ 1,064,965 |

Notes:
(A) Line 3 x Line 5
(B) Line 4a x Line 6a
(C) Line 4b x Line 6b

Totals may not tie due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
**January 2003 - December 2003**

O&M Activities
(in Dollars)

| Line | | Actual JUL | Actual AUG | Actual SEP | Actual OCT | Actual NOV | Actual DEC | 6-Month Sub-Total | 12-Month Total | Method of Classification CP Demand | GCP Demand | Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | | | | | | | | |
| 1 | Air Operating Permit Fees-O&M | $ 6,083 | $ 13,108 | $ 8,864 | $ 6,085 | $ 6,085 | $ 1,856,083 | $ 1,896,308 | $ 1,805,360 | - | | $ 1,805,360 |
| 3a | Continuous Emission Monitoring Systems-O&M | 32,524 | 38,775 | 118,060 | 25,166 | 43,109 | 35,426 | 293,060 | 526,519 | - | | 526,519 |
| 4a | Clean Closure Equivalency-O&M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - | | - |
| 5a | Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M | 0 | 3,400 | 0 | 3,632 | 78 | 23,294 | 30,404 | 82,169 | 82,169 | | - |
| 8a | Oil Spill Cleanup/Response Equipment-O&M | 6,752 | 6,598 | 10,063 | 13,583 | 11,080 | 18,614 | 66,690 | 107,580 | - | | 107,580 |
| 13 | RCRA Corrective Action-O&M | 0 | 0 | 0 | 0 | 0 | 61,083 | 61,083 | 63,581 | 63,581 | | - |
| 14 | NPDES Permit Fees-O&M | 0 | 7,500 | 0 | 0 | 0 | 11,500 | 19,000 | 142,543 | 142,543 | | - |
| 17a | Disposal of Noncontainerized Liquid Waste-O&M | 0 | 60,218 | 37,480 | 25,537 | 0 | 114,325 | 237,560 | 367,698 | | | 367,698 |
| 19a | Substation Pollutant Discharge Prevention & Removal - Distribution - O&M | 168,477 | 70,370 | 80,044 | 72,297 | 142,111 | 20,608 | 553,907 | 1,228,656 | | 1,228,656 | |
| 19b | Substation Pollutant Discharge Prevention & Removal - Transmission - O&M | 20,485 | 51,222 | 22,063 | 32,530 | 58,444 | 32,366 | 217,110 | 452,922 | 418,082 | | 34,840 |
| 19c | Substation Pollutant Discharge Prevention & Removal - Costs included in Base Rates | (46,686) | (46,686) | (46,686) | (46,686) | (46,686) | (46,686) | (280,116) | (560,232) | (258,569) | (280,116) | (21,547) |
| 20 | Wastewater Discharge Elimination & Reuse | 0 | 0 | 0 | 0 | 0 | 7,085 | 7,085 | 29,696 | 29,696 | | |
| N/A | Amortization of Gains on Sales of Emission Allowances | (66,111) | (40,184) | (40,184) | (40,184) | (40,184) | (40,184) | (267,031) | (482,207) | | | (482,207) |
| 22 | Pipeline Integrity Management | 0 | 0 | 0 | 0 | 0 | 105,000 | 105,000 | 177,784 | 177,784 | | |
| 23 | Spill Prevention, Control & Countermeasures (SPCC) | 49,949 | 6,219 | 21,613 | 7,840 | 360 | 6,608 | 92,589 | 160,850 | 160,850 | | |
| 2 | Total of O&M Activities | $ 171,473 | $ 170,540 | $ 211,317 | $ 99,800 | $ 174,397 | $ 2,205,122 | $ 3,032,649 | $ 4,102,919 | $ 816,136 | $ 948,540 | $ 2,338,243 |
| 3 | Recoverable Costs Allocated to Energy | $ (20,972) | $ 80,660 | $ 134,185 | $ 30,894 | $ 22,790 | $ 1,984,958 | $ 2,232,514 | $ 2,338,243 | | | |
| 4a | Recoverable Costs Allocated to CP Demand | $ 47,311 | $ 42,853 | $ 20,431 | $ 19,952 | $ 32,839 | $ 222,899 | $ 386,286 | $ 816,136 | | | |
| 4b | Recoverable Costs Allocated to GCP Demand | $ 145,134 | $ 47,027 | $ 56,701 | $ 48,954 | $ 118,768 | $ (2,735) | $ 413,849 | $ 948,540 | | | |
| 5 | Retail Energy Jurisdictional Factor | 98.97818% | 98.97818% | 98.97818% | 98.97818% | 98.97818% | 98.97818% | | | | | |
| 6a | Retail CP Demand Jurisdictional Factor | 99.01742% | 99.01742% | 99.01742% | 99.01742% | 99.01742% | 99.01742% | | | | | |
| 6b | Retail GCP Demand Jurisdictional Factor | 100.00000% | 100.00000% | 100.00000% | 100.00000% | 100.00000% | 100.00000% | | | | | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | ($20,758) | $79,835 | $132,813 | $30,578 | $22,557 | $1,964,675 | $2,209,700 | $2,314,347 | | | |
| 8a | Jurisdictional CP Demand Recoverable Costs (B) | $46,846 | $42,432 | $20,231 | $19,756 | $32,516 | $220,709 | $382,490 | $808,117 | | | |
| 8b | Jurisdictional GCP Demand Recoverable Costs (C) | $145,134 | $47,027 | $56,701 | $48,954 | $118,768 | ($2,735) | $413,849 | $948,540 | | | |
| 9 | Total Jurisdictional Recoverable Costs for O&M Activities | $ 171,222 | $ 169,294 | $ 209,745 | $ 99,288 | $ 173,841 | $ 2,182,649 | $ 3,006,039 | $ 4,071,004 | | | |

Notes:
(A) Line 3 x Line 5
(B) Line 4a x Line 6a
(C) Line 4b x Line 6b

Totals may not tie due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
**January 2003 - December 2003**

Variance Report of Capital Investment Projects-Recoverable Costs
(in Dollars)

| Line | | (1) Actual | (2) Estimated Actual | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1 | Description of Investment Projects | | | | |
| 2 | Low NOx Burner Technology-Capital | $2,179,804 | $2,072,617 | $107,187 | 5.2% |
| 3b | Continuous Emission Monitoring Systems-Capital | $1,538,721 | $1,492,921 | $45,800 | 3.1% |
| 4b | Clean Closure Equivalency-Capital | $6,365 | $6,132 | $233 | 3.8% |
| 5b | Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital | $1,535,262 | $1,506,397 | $28,865 | 1.9% |
| 7 | Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital | $3,537 | $3,391 | $146 | 4.3% |
| 8b | Oil Spill Cleanup/Response Equipment-Capital | $139,568 | $135,506 | $4,062 | 3.0% |
| 10 | Relocate Storm Water Runoff-Capital | $12,198 | $11,898 | $300 | 2.5% |
| NA | SO2 Allowances-Negative Return on Investment | ($147,502) | ($145,847) | ($1,655) | 1.1% |
| 12 | Scherer Discharge Pipeline-Capital | $93,741 | $90,844 | $2,897 | 3.2% |
| 17b | Disposal of Noncontainerized Liquid Wate-Capital | $53,337 | $50,581 | $2,756 | 5.4% |
| 20 | Wastewater Discharge Elimination & Reuse | $211,697 | $214,086 | ($2,389) | -1.1% |
| 21 | St. Lucie Turtle Net | $86,151 | $86,640 | ($489) | -0.6% |
| 22 | Pipeline Integrity Management | $0 | $11,062 | ($11,062) | -100.0% |
| 23 | Spill Prevention, Control & Countermeasures (SPCC) | $57,587 | $159,772 | ($102,185) | -64.0% |
| 2 | Total Investment Projects-Recoverable Costs | $5,770,466 | $5,696,000 | $ 74,466 | 1.3% |
| 3 | Recoverable Costs Allocated to Energy | $ 3,740,211 | $ 3,594,793 | $ 145,418 | 4.0% |
| 4 | Recoverable Costs Allocated to Demand | $ 2,030,255 | $ 2,101,207 | $ (70,952) | -3.4% |

Notes:
Column(1) is the End of Period Totals on Form 42-7A
Column(2) is the approved projected amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
**January 2003 - December 2003**

Capital Investment Projects-Recoverable Costs
(in Dollars)

| Line | | Actual JAN | Actual FEB | Actual MAR | Actual APR | Actual MAY | Actual JUN | 6-Month Sub-Total |
|---|---|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects (A) | | | | | | | |
| 2 | Low NOx Burner Technology-Capital | $177,623 | $176,731 | $175,840 | $174,948 | $174,056 | $173,164 | 1,052,362 |
| 3b | Continuous Emission Monitoring Systems-Capital | 125,317 | 124,791 | 124,264 | 128,349 | 124,241 | 122,391 | 749,353 |
| 4b | Clean Closure Equivalency-Capital | 522 | 520 | 518 | 516 | 514 | 512 | 3,102 |
| 5b | Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital | 126,071 | 125,776 | 125,480 | 125,185 | 124,890 | 124,462 | 751,864 |
| 7 | Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital | 289 | 288 | 287 | 286 | 284 | 283 | 1,717 |
| 8b | Oil Spill Cleanup/Response Equipment-Capital | 11,360 | 11,292 | 11,355 | 11,320 | 11,320 | 11,268 | 67,915 |
| 10 | Relocate Storm Water Runoff-Capital | 1,005 | 1,003 | 1,000 | 998 | 995 | 993 | 5,994 |
| NA | SO2 Allowances-Negative Return on Investment | (11,673) | (11,583) | (11,493) | (11,402) | (11,312) | (12,394) | (69,857) |
| 12 | Scherer Discharge Pipeline-Capital | 7,703 | 7,679 | 7,655 | 7,631 | 7,606 | 7,582 | 45,856 |
| 17 | Disposal of NonContainerized Liquid Waste-Capital | 4,382 | 4,352 | 4,321 | 4,291 | 4,261 | 4,230 | 25,837 |
| 20 | Wastewater Discharge Elimination and Reuse | 17,399 | 17,345 | 17,292 | 17,238 | 17,184 | 17,130 | 103,588 |
| 21 | St. Lucie Turtle Net | 7,153 | 7,302 | 7,291 | 7,281 | 7,263 | 7,246 | 43,536 |
| 22 | Pipeline Integrity Management | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 23 | Spill Prevention, Control & Countermeasures (SPCC) | 0 | 0 | 0 | 73 | 1,148 | 2,213 | 3,434 |
| 2 | Total Investment Projects - Recoverable Costs | $467,151 | $465,496 | $463,810 | $466,714 | $462,450 | $459,080 | $2,784,701 |
| 3 | Recoverable Costs Allocated to Energy | $304,797 | $303,443 | $302,088 | $305,343 | $300,482 | $296,693 | $ 1,812,846 |
| 4 | Recoverable Costs Allocated to Demand | $162,354 | $162,053 | $161,722 | $161,371 | $161,968 | $162,387 | $ 971,855 |
| 5 | Retail Energy Jurisdictional Factor | 98.97818% | 98.97818% | 98.97818% | 98.97818% | 98.97818% | 98.97818% | |
| 6 | Retail Demand Jurisdictional Factor | 99.01742% | 99.01742% | 99.01742% | 99.01742% | 99.01742% | 99.01742% | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | $301,682 | $300,343 | $299,001 | $ 302,223 | $ 297,412 | $ 293,662 | $ 1,794,323 |
| 8 | Jurisdictional Demand Recoverable Costs (C) | $160,759 | $160,460 | $160,133 | $ 159,786 | $ 160,376 | $ 160,791 | $ 962,305 |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects | $462,441 | $460,803 | $459,134 | $ 462,009 | $ 457,788 | $ 454,453 | $ 2,756,628 |

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
January 2003 - December 2003

Capital Investment Projects-Recoverable Costs
(in Dollars)

| Line | | Actual JUL | Actual AUG | Actual SEP | Actual OCT | Actual NOV | Actual DEC | 6-Month Sub-Total | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects (A) | | | | | | | | | | |
| 2 | Low NOx Burner Technology-Capital | $283,918 | $170,488 | $169,597 | $168,705 | $167,813 | $166,921 | $1,127,442 | $2,179,804 | - | $2,179,804 |
| 3b | Continuous Emission Monitoring Systems-Capital | 187,364 | 122,742 | 120,529 | 119,996 | 119,451 | 119,286 | $789,368 | $1,538,721 | - | 1,538,721 |
| 4b | Clean Closure Equivalency-Capital | 753 | 506 | 504 | 502 | 500 | 498 | $3,263 | $6,365 | 5,875 | 490 |
| 5b | Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital | 160,738 | 122,969 | 122,195 | 121,902 | 125,663 | 129,931 | $783,398 | $1,535,262 | 1,417,165 | 118,097 |
| 7 | Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital | 434 | 280 | 278 | 277 | 276 | 275 | $1,820 | $3,537 | 3,265 | 272 |
| 8b | Oil Spill Cleanup/Response Equipment-Capital | 19,278 | 10,483 | 10,464 | 10,515 | 10,444 | 10,469 | $71,653 | $139,568 | 128,832 | 10,736 |
| 10 | Relocate Storm Water Runoff-Capital | 1,303 | 985 | 983 | 980 | 978 | 975 | $6,204 | $12,198 | 11,260 | 938 |
| NA | SO2 Allowances-Negative Return on Investment | (13,568) | (13,455) | (13,135) | (12,815) | (12,496) | (12,176) | ($77,645) | ($147,502) | | (147,502) |
| 12 | Scherer Discharge Pipeline-Capital | 10,575 | 7,510 | 7,486 | 7,462 | 7,438 | 7,414 | $47,885 | $93,741 | 86,530 | 7,211 |
| 17 | Disposal of Noncontainerized Liquid Waste-Capital | 7,852 | 3,988 | 3,959 | 3,930 | 3,900 | 3,871 | $27,500 | $53,337 | 49,234 | 4,103 |
| 20 | Wastewater Discharge Elimination and Reuse | 23,799 | 16,969 | 16,916 | 16,862 | 16,808 | 16,755 | $108,109 | $211,697 | 195,413 | 16,284 |
| 21 | St. Lucie Turtle Net | 6,827 | 7,193 | 7,175 | 7,158 | 7,140 | 7,122 | $42,615 | $86,151 | 79,524 | 6,627 |
| 22 | Pipeline Integrity Management | 0 | 0 | 0 | 0 | 0 | 0 | $0 | $0 | 0 | - |
| 23 | Spill Prevention, Control & Countermeasures (SPCC) | 4,917 | 7,273 | 8,446 | 8,173 | 10,545 | 14,799 | $54,153 | $57,587 | 53,157 | 4,430 |
| 2 | Total Investment Projects - Recoverable Costs | $ 694,190 | $ 457,931 | $ 455,397 | $ 453,647 | $ 458,460 | $ 466,140 | $ 2,985,765 | $ 5,770,466 | $ 2,030,255 | $ 3,740,211 |
| 3 | Recoverable Costs Allocated to Energy | $ 475,904 | $ 293,479 | $ 290,715 | $ 289,560 | $ 288,898 | $ 288,809 | $ 1,927,365 | $ 3,740,211 | | |
| 4 | Recoverable Costs Allocated to Demand | $ 218,286 | $ 164,452 | $ 164,682 | $ 164,087 | $ 169,562 | $ 177,331 | $ 1,058,400 | $ 2,030,255 | | |
| 5 | Retail Energy Jurisdictional Factor | 98.97818% | 98.97818% | 98.97818% | 98.97818% | 98.97818% | 98.97818% | | | | |
| 6 | Retail Demand Jurisdictional Factor | 99.01742% | 99.01742% | 99.01742% | 99.01742% | 99.01742% | 99.01742% | | | | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | $ 471,042 | $ 290,480 | $ 287,744 | $ 286,601 | $ 285,946 | $ 285,858 | $ 1,907,671 | $ 3,701,994 | | |
| 8 | Jurisdictional Demand Recoverable Costs (C) | $ 216,141 | $ 162,836 | $ 163,064 | $ 162,475 | $ 167,896 | $ 175,589 | $ 1,048,000 | $ 2,010,305 | | |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects | $ 687,182 | $ 453,316 | $ 450,808 | $ 449,076 | $ 453,842 | $ 461,446 | $ 2,955,671 | $ 5,712,299 | | |

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 9,319,144 | 9,431,236 | 9,543,328 | 9,655,420 | 9,767,512 | 9,679,603 | 9,991,695 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $8,292,324 | $8,180,232 | $8,068,140 | $7,956,048 | $7,843,956 | $7,731,865 | $7,619,773 | n/a |
| 6. | Average Net Investment | | 8,236,278 | 8,124,186 | 8,012,094 | 7,900,002 | 7,787,910 | 7,675,819 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 48,813 | 48,149 | 47,485 | 46,820 | 46,156 | 45,492 | 282,914 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 16,718 | 16,491 | 16,263 | 16,036 | 15,808 | 15,581 | 96,897 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 112,092 | 112,092 | 112,092 | 112,092 | 112,092 | 112,092 | 672,551 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $177,623 | $176,731 | $175,840 | $174,948 | $174,056 | $173,164 | $1,052,362 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
**For the Period July through December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(In Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 9,991,695 | 10,215,879 | 10,327,971 | 10,440,063 | 10,552,154 | 10,664,246 | 10,776,338 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $7,619,773 | $7,395,589 | $7,283,497 | $7,171,405 | $7,059,314 | $6,947,222 | $6,835,130 | n/a |
| 6. | Average Net Investment | | 7,507,681 | 7,339,543 | 7,227,451 | 7,115,360 | 7,003,268 | 6,891,176 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 44,495 | 43,499 | 42,834 | 42,170 | 41,506 | 40,841 | 538,259 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 15,239 | 14,898 | 14,671 | 14,443 | 14,215 | 13,988 | 184,351 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 224,184 | 112,092 | 112,092 | 112,092 | 112,092 | 112,092 | 1,457,194 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $283,918 | $170,488 | $169,597 | $168,705 | $167,813 | $166,921 | $2,179,804 |

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $75,745 | $21,331 | ($5,231) | $91,844 |
| | c. Retirements | | | | | $9,059 | $21,320 | $4,656 | $35,035 |
| | d. Other (A) | | | | | | | $159 | $159 |
| 2. | Plant-In-Service/Depreciation Base (B) | $12,557,643 | 12,557,643 | 12,557,643 | 12,557,643 | 12,624,329 | 12,624,339 | 12,614,452 | 0 |
| 3. | Less: Accumulated Depreciation (C) | 4,800,702 | 4,866,851 | 4,932,999 | 4,999,148 | 5,059,665 | 5,104,864 | 5,165,178 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $7,756,941 | $7,690,792 | $7,624,644 | $7,558,495 | $7,564,664 | $7,519,475 | $7,449,274 | n/a |
| 6. | Average Net Investment | | 7,723,867 | 7,657,718 | 7,591,570 | 7,561,579 | 7,542,069 | 7,484,375 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 45,776 | 45,384 | 44,992 | 44,814 | 44,699 | 44,357 | 270,023 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 15,678 | 15,544 | 15,410 | 15,349 | 15,309 | 15,192 | 92,482 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 66,149 | 66,149 | 66,149 | 70,471 | 66,519 | 65,128 | 400,565 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (2,286) | (2,286) | (2,286) | (2,286) | (2,286) | (2,286) | (13,716) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $125,317 | $124,791 | $124,264 | $128,349 | $124,241 | $122,391 | $749,353 |

Notes:

(A) Cost of removal in June.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) Depreciation offset for base rate retirements.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
**For the Period July through December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $84,501 | $46,385 | ($45) | ($953) | $0 | $82,646 | $304,379 |
| | c. Retirements | | $54,714 | $158,719 | | | | $64,685 | $313,153 |
| | d. Other (A) | | | $241,962 | | | | | $242,120 |
| 2. | Plant-In-Service/Depreciation Base (B) | $12,614,452 | 12,644,239 | 12,531,905 | 12,531,860 | 12,530,908 | 12,530,908 | 12,548,869 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 5,165,178 | 5,243,393 | 5,393,824 | 5,460,110 | 5,526,394 | 5,592,663 | 5,594,282 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $7,449,274 | $7,400,846 | $7,138,081 | $7,071,750 | $7,004,514 | $6,938,244 | $6,954,586 | n/a |
| 6. | Average Net Investment | | 7,425,060 | 7,269,463 | 7,104,915 | 7,038,132 | 6,971,379 | 6,946,415 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 44,005 | 43,083 | 42,108 | 41,712 | 41,317 | 41,169 | 523,417 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 15,072 | 14,756 | 14,422 | 14,286 | 14,151 | 14,100 | 179,268 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 132,859 | 67,189 | 66,286 | 66,284 | 66,269 | 66,303 | 865,754 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (4,572) | (2,286) | (2,286) | (2,286) | (2,286) | (2,286) | (29,718) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $187,364 | $122,742 | $120,529 | $119,996 | $119,451 | $119,286 | $1,538,721 |

**Notes:**

(A) Reseve transfer in August.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) Depreciation offset for base rate retirements.

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Period January through June 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $58,866 | 58,866 | 58,866 | 58,866 | 58,866 | 58,866 | 58,866 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 23,882 | 24,126 | 24,370 | 24,615 | 24,859 | 25,103 | 25,348 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $34,984 | $34,740 | $34,496 | $34,251 | $34,007 | $33,763 | $33,518 | n/a |
| 6. | Average Net Investment | | 34,862 | 34,618 | 34,373 | 34,129 | 33,885 | 33,640 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 207 | 205 | 204 | 202 | 201 | 199 | 1,218 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 71 | 70 | 70 | 69 | 69 | 68 | 417 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 244 | 244 | 244 | 244 | 244 | 244 | 1,466 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $522 | $520 | $518 | $516 | $514 | $512 | $3,102 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $58,866 | 58,866 | 58,866 | 58,866 | 58,866 | 58,866 | 58,866 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 25,348 | 25,836 | 26,081 | 26,325 | 26,569 | 26,814 | 27,058 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $33,518 | $33,030 | $32,785 | $32,541 | $32,297 | $32,052 | $31,808 | n/a |
| 6. | Average Net Investment | | 33,274 | 32,907 | 32,663 | 32,419 | 32,174 | 31,930 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 197 | 195 | 194 | 192 | 191 | 189 | 2,376 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 68 | 67 | 66 | 66 | 65 | 65 | 814 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 489 | 244 | 244 | 244 | 244 | 244 | 3,176 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $753 | $506 | $504 | $502 | $500 | $498 | $6,365 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | | | | | | | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $12,423,132 | 12,423,132 | 12,423,132 | 12,423,132 | 12,423,132 | 12,423,132 | 12,423,132 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 1,224,118 | 1,261,232 | 1,298,347 | 1,335,461 | 1,372,575 | 1,409,690 | 1,446,671 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $11,199,014 | $11,161,900 | $11,124,785 | $11,087,671 | $11,050,557 | $11,013,442 | $10,976,461 | n/a |
| 6. | Average Net Investment | | 11,180,457 | 11,143,342 | 11,106,228 | 11,069,114 | 11,031,999 | 10,994,951 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 66,262 | 66,042 | 65,822 | 65,602 | 65,382 | 65,163 | 394,274 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 22,694 | 22,619 | 22,544 | 22,468 | 22,393 | 22,316 | 135,037 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 37,114 | 37,114 | 37,114 | 37,114 | 37,114 | 36,982 | 222,553 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $126,071 | $125,776 | $125,480 | $125,185 | $124,890 | $124,462 | $751,864 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $889,324 | $111,820 | $1,001,144 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | $120,775 | | | | | $120,775 |
| 2. | Plant-In-Service/Depreciation Base (B) | $12,423,132 | 12,423,132 | 12,423,132 | 12,423,132 | 12,423,132 | 13,312,456 | 13,424,276 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 1,446,671 | 1,520,369 | 1,677,992 | 1,714,841 | 1,751,690 | 1,789,058 | 1,827,009 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $10,976,461 | $10,902,763 | $10,745,140 | $10,708,291 | $10,671,442 | $11,523,398 | $11,597,267 | n/a |
| 6. | Average Net Investment | | 10,939,612 | 10,823,951 | 10,726,715 | 10,689,866 | 11,097,420 | 11,560,332 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 64,835 | 64,149 | 63,573 | 63,355 | 65,770 | 68,514 | 784,469 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 22,206 | 21,971 | 21,773 | 21,699 | 22,526 | 23,466 | 268,677 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 73,698 | 36,849 | 36,849 | 36,849 | 37,368 | 37,952 | 482,117 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $160,738 | $122,969 | $122,195 | $121,902 | $125,663 | $129,931 | $1,535,262 |

**Notes:**

(A) Reseve transfer in August.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
**For the Period January through June 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $31,030 | 31,030 | 31,030 | 31,030 | 31,030 | 31,030 | 31,030 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 13,765 | 13,917 | 14,070 | 14,222 | 14,375 | 14,527 | 14,680 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $17,265 | $17,113 | $16,960 | $16,808 | $16,655 | $16,503 | $16,350 | n/a |
| 6. | Average Net Investment | | 17,189 | 17,037 | 16,884 | 16,732 | 16,579 | 16,426 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 102 | 101 | 100 | 99 | 98 | 97 | 598 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 35 | 35 | 34 | 34 | 34 | 33 | 205 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 153 | 153 | 153 | 153 | 153 | 153 | 915 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $289 | $288 | $287 | $286 | $284 | $283 | $1,717 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $31,030 | 31,030 | 31,030 | 31,030 | 31,030 | 31,030 | 31,030 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 14,680 | 14,985 | 15,138 | 15,290 | 15,443 | 15,595 | 15,748 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $16,350 | $16,045 | $15,892 | $15,740 | $15,587 | $15,435 | $15,282 | n/a |
| 6. | Average Net Investment | | 16,198 | 15,969 | 15,816 | 15,664 | 15,511 | 15,358 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 96 | 95 | 94 | 93 | 92 | 91 | 1,158 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 33 | 32 | 32 | 32 | 31 | 31 | 397 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 305 | 153 | 153 | 153 | 153 | 153 | 1,983 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $434 | $280 | $278 | $277 | $276 | $275 | $3,537 |

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
**For the Period January through June 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $8,262 | $0 | $4,363 | $0 | $12,625 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $726,086 | 726,086 | 726,086 | 734,348 | 734,348 | 738,711 | 738,711 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 365,630 | 374,156 | 382,682 | 391,307 | 399,931 | 408,607 | 417,284 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $360,456 | $351,930 | $343,404 | $343,042 | $334,417 | $330,104 | $321,428 | n/a |
| 6. | Average Net Investment | | 356,193 | 347,667 | 343,223 | 338,730 | 332,261 | 325,766 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 2,111 | 2,060 | 2,034 | 2,008 | 1,969 | 1,931 | 12,113 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 723 | 706 | 697 | 688 | 674 | 661 | 4,149 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 8,526 | 8,526 | 8,624 | 8,624 | 8,676 | 8,676 | 51,654 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $11,360 | $11,292 | $11,355 | $11,320 | $11,320 | $11,268 | $67,915 |

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $2,467 | $0 | $4,499 | $3,278 | $0 | $5,046 | $27,915 |
| | c. Retirements | | | $38,828 | | | | | $38,828 |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $738,711 | 741,178 | 702,350 | 706,849 | 710,126 | 710,126 | 715,172 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 417,284 | 434,062 | 403,305 | 411,404 | 419,588 | 427,752 | 435,987 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $321,428 | $307,117 | $299,045 | $295,445 | $290,538 | $282,374 | $279,185 | n/a |
| 6. | Average Net Investment | | 314,272 | 303,081 | 297,245 | 292,992 | 286,456 | 280,779 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 1,863 | 1,796 | 1,762 | 1,736 | 1,698 | 1,664 | 22,632 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 638 | 615 | 603 | 595 | 581 | 570 | 7,751 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 16,778 | 8,072 | 8,099 | 8,184 | 8,165 | 8,235 | 109,185 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $19,278 | $10,483 | $10,464 | $10,515 | $10,444 | $10,469 | $139,568 |

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.81425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
**For the Period January through June 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $117,794 | 117,794 | 117,794 | 117,794 | 117,794 | 117,794 | 117,794 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 30,767 | 31,081 | 31,395 | 31,709 | 32,023 | 32,337 | 32,651 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $87,027 | $86,713 | $86,399 | $86,085 | $85,771 | $85,457 | $85,143 | n/a |
| 6. | Average Net Investment | | 86,870 | 86,556 | 86,242 | 85,928 | 85,614 | 85,300 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 515 | 513 | 511 | 509 | 507 | 506 | 3,061 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 176 | 176 | 175 | 174 | 174 | 173 | 1,048 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 314 | 314 | 314 | 314 | 314 | 314 | 1,885 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $1,005 | $1,003 | $1,000 | $998 | $995 | $993 | $5,994 |

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $117,794 | 117,794 | 117,794 | 117,794 | 117,794 | 117,794 | 117,794 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 32,651 | 33,280 | 33,594 | 33,908 | 34,222 | 34,536 | 34,850 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $85,143 | $84,514 | $84,200 | $83,886 | $83,572 | $83,258 | $82,944 | n/a |
| 6. | Average Net Investment | | 84,828 | 84,357 | 84,043 | 83,729 | 83,415 | 83,101 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 503 | 500 | 498 | 496 | 494 | 493 | 6,045 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 172 | 171 | 171 | 170 | 169 | 169 | 2,070 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 628 | 314 | 314 | 314 | 314 | 314 | 4,083 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $1,303 | $985 | $983 | $980 | $978 | $975 | $12,198 |

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $864,260 | 864,260 | 864,260 | 864,260 | 864,260 | 864,260 | 864,260 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 275,308 | 278,337 | 281,366 | 284,395 | 287,423 | 290,452 | 293,481 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $588,952 | $585,923 | $582,894 | $579,865 | $576,837 | $573,808 | $570,779 | n/a |
| 6. | Average Net Investment | | 587,438 | 584,409 | 581,380 | 578,351 | 575,322 | 572,293 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 3,482 | 3,464 | 3,446 | 3,428 | 3,410 | 3,392 | 20,620 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 1,192 | 1,186 | 1,180 | 1,174 | 1,168 | 1,162 | 7,062 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 3,029 | 3,029 | 3,029 | 3,029 | 3,029 | 3,029 | 18,173 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $7,703 | $7,679 | $7,655 | $7,631 | $7,606 | $7,582 | $45,856 |

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $864,260 | 864,260 | 864,260 | 864,260 | 864,260 | 864,260 | 864,260 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 293,481 | 299,539 | 302,568 | 305,597 | 308,626 | 311,655 | 314,684 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $570,779 | $564,721 | $561,692 | $558,663 | $555,634 | $552,605 | $549,577 | n/a |
| 6. | Average Net Investment | | 567,750 | 563,207 | 560,178 | 557,149 | 554,120 | 551,091 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 3,365 | 3,338 | 3,320 | 3,302 | 3,284 | 3,266 | 40,495 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 1,152 | 1,143 | 1,137 | 1,131 | 1,125 | 1,119 | 13,869 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 6,058 | 3,029 | 3,029 | 3,029 | 3,029 | 3,029 | 39,376 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $10,575 | $7,510 | $7,486 | $7,462 | $7,438 | $7,414 | $93,741 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $311,009 | 311,009 | 311,009 | 311,009 | 311,009 | 311,009 | 311,009 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 238,429 | 242,249 | 246,069 | 249,889 | 253,709 | 257,529 | 261,349 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $72,580 | $68,760 | $64,940 | $61,120 | $57,300 | $53,480 | $49,660 | n/a |
| 6. | Average Net Investment | | 70,670 | 66,850 | 63,030 | 59,210 | 55,390 | 51,570 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 419 | 396 | 374 | 351 | 328 | 306 | 2,173 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 143 | 136 | 128 | 120 | 112 | 105 | 744 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 3,820 | 3,820 | 3,820 | 3,820 | 3,820 | 3,820 | 22,920 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $4,382 | $4,352 | $4,321 | $4,291 | $4,261 | $4,230 | $25,837 |

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $311,009 | 311,009 | 311,009 | 311,009 | 311,009 | 311,009 | 311,009 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 261,349 | 268,836 | 272,503 | 276,170 | 279,837 | 283,504 | 287,172 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $49,660 | $42,173 | $38,506 | $34,839 | $31,172 | $27,505 | $23,837 | n/a |
| 6. | Average Net Investment | | 45,917 | 40,339 | 36,672 | 33,005 | 29,338 | 25,671 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 272 | 239 | 217 | 196 | 174 | 152 | 3,424 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 93 | 82 | 74 | 67 | 60 | 52 | 1,173 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 7,487 | 3,667 | 3,667 | 3,667 | 3,667 | 3,667 | 48,743 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $7,852 | $3,988 | $3,959 | $3,930 | $3,900 | $3,871 | $53,337 |

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
**For the Period January through June 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 222,099 | 228,848 | 235,597 | 242,346 | 249,095 | 255,844 | 262,593 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $1,341,896 | $1,335,147 | $1,328,398 | $1,321,649 | $1,314,900 | $1,308,151 | $1,301,402 | n/a |
| 6. | Average Net Investment | | 1,338,521 | 1,331,772 | 1,325,023 | 1,318,274 | 1,311,525 | 1,304,776 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 7,933 | 7,893 | 7,853 | 7,813 | 7,773 | 7,733 | 46,997 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 2,717 | 2,703 | 2,690 | 2,676 | 2,662 | 2,648 | 16,096 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 6,749 | 6,749 | 6,749 | 6,749 | 6,749 | 6,749 | 40,494 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $17,399 | $17,345 | $17,292 | $17,238 | $17,184 | $17,130 | $103,588 |

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $262,593 | 276,092 | 282,841 | 289,590 | 296,339 | 303,088 | 309,837 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $1,301,402 | $1,287,903 | $1,281,154 | $1,274,405 | $1,267,656 | $1,260,907 | $1,254,158 | n/a |
| 6. | Average Net Investment | | 1,294,652 | 1,284,528 | 1,277,779 | 1,271,030 | 1,264,281 | 1,257,532 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | Equi Equity Component grossed up for taxes (D) | | 7,673 | 7,613 | 7,573 | 7,533 | 7,493 | 7,453 | 92,335 |
| | Debt Component (Line 6 x 2.4358% x 1/12) | | 2,628 | 2,607 | 2,594 | 2,580 | 2,566 | 2,553 | 31,624 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 13,499 | 6,749 | 6,749 | 6,749 | 6,749 | 6,749 | 87,738 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $23,799 | $16,969 | $16,916 | $16,862 | $16,808 | $16,755 | $211,697 |

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $31,304 | $0 | $1,296 | $0 | $0 | $0 | $32,599 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $796,190 | 827,494 | 827,494 | 828,789 | 828,789 | 828,789 | 828,789 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 1,062 | 3,226 | 5,433 | 7,641 | 9,852 | 12,062 | 14,272 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $795,128 | $824,267 | $822,060 | $821,148 | $818,938 | $816,727 | $814,517 | n/a |
| 6. | Average Net Investment | | 809,698 | 823,164 | 821,604 | 820,043 | 817,832 | 815,622 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 4,799 | 4,879 | 4,869 | 4,860 | 4,847 | 4,834 | 29,088 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 1,644 | 1,671 | 1,668 | 1,665 | 1,660 | 1,656 | 9,962 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 2,165 | 2,207 | 2,208 | 2,210 | 2,210 | 2,210 | 13,210 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (1,454) | (1,454) | (1,454) | (1,454) | (1,454) | (1,454) | (8,724) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $7,153 | $7,302 | $7,291 | $7,281 | $7,263 | $7,246 | $43,536 |

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) Depreciation offset for base rate items.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $32,599 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $828,789 | 828,789 | 828,789 | 828,789 | 828,789 | 828,789 | 828,789 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $14,272 | 18,692 | 20,903 | 23,113 | 25,323 | 27,533 | 29,743 | n/a |
| 4. | CWIP - Non Interest Bearing | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $814,517 | $810,097 | $807,886 | $805,676 | $803,466 | $801,256 | $799,046 | n/a |
| 6. | Average Net Investment | | 812,307 | 808,992 | 806,781 | 804,571 | 802,361 | 800,151 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 4,814 | 4,795 | 4,781 | 4,768 | 4,755 | 4,742 | 57,744 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 1,649 | 1,642 | 1,638 | 1,633 | 1,629 | 1,624 | 19,777 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 3,272 | 2,210 | 2,210 | 2,210 | 2,210 | 2,210 | 27,532 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (2,908) | (1,454) | (1,454) | (1,454) | (1,454) | (1,454) | (18,902) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $6,827 | $7,193 | $7,175 | $7,158 | $7,140 | $7,122 | $86,151 |

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) Depreciation offset for base rate items.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $14,837 | $205,128 | $12,986 | $232,951 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 14,837 | 219,965 | 232,951 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 0 | 0 | 0 | 0 | 14 | 229 | 644 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $0 | $0 | $0 | $0 | $14,823 | $219,736 | $232,307 | n/a |
| 6. | Average Net Investment | | 0 | 0 | 0 | 7,412 | 117,280 | 226,022 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 0 | 0 | 0 | 44 | 695 | 1,340 | 2,079 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 0 | 0 | 0 | 15 | 238 | 459 | 712 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 0 | 0 | 0 | 14 | 215 | 415 | 644 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $0 | $0 | $0 | $73 | $1,148 | $2,213 | $3,434 |

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $344,319 | $285,021 | $11,815 | ($65,019) | $552,418 | $320,733 | $1,682,237 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | $1,712 | | | | | $1,712 |
| 2. | Plant-In-Service/Depreciation Base (B) | $232,951 | 577,270 | 862,291 | 874,105 | 809,086 | 1,361,504 | 1,682,237 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $644 | 2,665 | 5,959 | 7,550 | 9,093 | 11,083 | 13,873 | n/a |
| 4. | CWIP - Non Interest Bearing | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $232,307 | $574,605 | $856,332 | $866,555 | $799,993 | $1,350,421 | $1,668,364 | n/a |
| 6. | Average Net Investment | | 403,456 | 715,468 | 861,444 | 833,274 | 1,075,207 | 1,509,393 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 2,391 | 4,240 | 5,105 | 4,938 | 6,372 | 8,946 | 34,072 |
| | b. Debt Component (Line 6 x 2.4358% x 1/12) | | 819 | 1,452 | 1,749 | 1,691 | 2,182 | 3,064 | 11,669 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 1,706 | 1,581 | 1,592 | 1,543 | 1,990 | 2,790 | 11,846 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $4,917 | $7,273 | $8,446 | $8,173 | $10,545 | $14,799 | $57,587 |

Notes:
(A) Reserve transfer in August.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 27-29.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 27-29.
(F) Applicable amortization period(s). See Form 42-8A, pages 27-29.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2003

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(in Dollars)

| Line | | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | End of Period Amount | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | |
| | a 158.100 Allowance Inventory | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| | b 158.200 Allowances Withheld | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| | c 182.300 Other Regulatory Assets-Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| | d 254.900 Other Regulatory Liabilities-Gains | | (1,472,809) | (1,461,467) | (1,450,125) | (1,438,784) | (1,427,442) | (1,416,100) | (1,699,384) | | |
| 2 | Total Working Capital | | ($1,472,809) | ($1,461,467) | ($1,450,125) | ($1,438,784) | ($1,427,442) | ($1,416,100) | ($1,699,384) | | |
| 3 | Average Net Working Capital Balance | | | (1,467,136) | (1,455,796) | (1,444,455) | (1,433,113) | (1,421,771) | (1,557,742) | | |
| 4 | Return on Average Net Working Capital Balance | | | | | | | | | | |
| | a Equity Component grossed up for taxes | (A) | | (8,695) | (8,628) | (8,561) | (8,493) | (8,426) | (9,232) | (52,036) | |
| | b Debt Component (Line 3 x 2.4358% x 1/12) | | | (2,978) | (2,955) | (2,932) | (2,909) | (2,886) | (3,162) | (17,822) | |
| 5 | Total Return Component | (D) | | ($11,673) | ($11,583) | ($11,493) | ($11,402) | ($11,312) | ($12,394) | ($69,858) | (D) |
| 6 | Expense Dr (Cr) | | | | | | | | | | |
| | a 411.800 Gains from Dispositions of Allowances | | | (11,342) | (11,342) | (11,342) | (11,342) | (11,342) | (158,466) | (215,175) | |
| | b 411.900 Losses from Dispositions of Allowances | | | 0 | 0 | 0 | 0 | 0 | 0 | - | |
| | c 509.000 Allowance Expense | | | 0 | 0 | 0 | 0 | 0 | 0 | - | |
| 7 | Net Expense (Lines 6a+6b+6c) | (E) | | ($11,342) | ($11,342) | ($11,342) | ($11,342) | ($11,342) | ($158,466) | ($215,175) | |
| 8 | Total System Recoverable Expenses (Lines 5+7) | | | (23,015) | (22,925) | (22,835) | (22,744) | (22,654) | (170,860) | | |
| | a Recoverable Costs Allocated to Energy | | | (23,015) | (22,925) | (22,835) | (22,744) | (22,654) | (170,860) | | |
| | b Recoverable Costs Allocated to Demand | | | 0 | 0 | 0 | 0 | 0 | 0 | | |
| 9 | Energy Jurisdictional Factor | | | 98.53755% | 98.53755% | 98.53755% | 98.53755% | 98.53755% | 98.53755% | | |
| 10 | Demand Jurisdictional Factor | | | 97.87297% | 97.87297% | 97.87297% | 97.87297% | 97.87297% | 97.87297% | | |
| 11 | Retail Energy-Related Recoverable Costs | (B) | | (22,678) | (22,589) | (22,501) | (22,412) | (22,323) | (168,361) | (280,864) | |
| 12 | Retail Demand-Related Recoverable Costs | (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 13 | Total Jurisdictional Recoverable Costs (Lines11+12) | | | ($22,678) | ($22,589) | ($22,501) | ($22,412) | ($22,323) | ($168,361) | ($280,864) | |

**Notes:**

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2003

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(in Dollars)

| Line | | Beginning of Period Amount | July Actual | August Actual | September Actual | October Actual | November Actual | December Actual | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | |
| | a 158.100 Allowance Inventory | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| | b 158.200 Allowances Withheld | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c 182.300 Other Regulatory Assets-Losses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d 254.900 Other Regulatory Liabilities-Gains | (1,699,384) | (1,711,155) | (1,670,971) | (1,630,787) | (1,590,604) | (1,550,420) | (1,510,236) | |
| 2 | Total Working Capital | ($1,699,384) | ($1,711,155) | ($1,670,971) | ($1,630,787) | ($1,590,604) | ($1,550,420) | ($1,510,236) | |
| 3 | Average Net Working Capital Balance | | (1,705,270) | (1,691,063) | (1,650,879) | (1,610,695) | (1,570,512) | (1,530,328) | |
| 4 | Return on Average Net Working Capital Balance | | | | | | | | |
| | a Equity Component grossed up for taxes | (A) | (10,106) | (10,022) | (9,784) | (9,546) | (9,306) | (9,070) | (109,872) |
| | b Debt Component (Line 3 x 2.4358% x 1/12) | | (3,461) | (3,433) | (3,351) | (3,269) | (3,188) | (3,106) | (37,631) |
| 5 | Total Return Component | (D) | ($13,568) | ($13,455) | ($13,135) | ($12,815) | ($12,496) | ($12,176) | ($147,503) |
| 6 | Expense Dr (Cr) | | | | | | | | |
| | a 411.800 Gains from Dispositions of Allowances | | (66,111) | (40,184) | (40,184) | (40,184) | (40,184) | (40,184) | (482,205) |
| | b 411.900 Losses from Dispositions of Allowances | | 0 | 0 | 0 | 0 | 0 | 0 | - |
| | c 509.000 Allowance Expense | | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 7 | Net Expense (Lines 6a+6b+6c) | (E) | ($66,111) | ($40,184) | ($40,184) | ($40,184) | ($40,184) | ($40,184) | (482,207) |
| 8 | Total System Recoverable Expenses (Lines 5+7) | | ($79,679) | ($53,639) | ($53,319) | ($52,999) | ($52,680) | ($52,360) | |
| | a Recoverable Costs Allocated to Energy | | (79,679) | (53,639) | (53,319) | (52,999) | (52,680) | (52,360) | |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | |
| 9 | Energy Jurisdictional Factor | | 98.53755% | 98.53755% | 98.53755% | 98.53755% | 98.53755% | 98.53755% | |
| 10 | Demand Jurisdictional Factor | | 97.87297% | 97.87297% | 97.87297% | 97.87297% | 97.87297% | 97.87297% | |
| 11 | Retail Energy-Related Recoverable Costs | (B) | (78,514) | (52,854) | (52,539) | (52,224) | (51,909) | (51,594) | (620,498) |
| 12 | Retail Demand-Related Recoverable Costs | (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Total Jurisdictional Recoverable Costs (Lines11+12) | | ($78,514) | ($52,854) | ($52,539) | ($52,224) | ($51,909) | ($51,594) | ($620,498) |

**Notes:**

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the Equity Component of 4.3685% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding.

FOR 2003

| Project No. | PLANT NAME | PLANT ACCOUNT | DEPRECIATION RATE/ AMORTIZATION PERIOD | ACTUAL JANUARY PLANT IN SERVICE (BOM) | ACTUAL DECEMBER PLANT IN SERVICE (EOM) |
|---|---|---|---|---|---|
| 02 | RIVIERA UNIT 3 | 312 | 8.90% | $3,846,591.65 | $3,846,591.65 |
| | RIVIERA UNIT 4 | 312 | 7.90% | $3,272,970.68 | $3,272,970.68 |
| | PT EVERGLADES UNIT 1 | 312 | 6.10% | $2,700,574.97 | $2,700,574.97 |
| | PT EVERGLADES UNIT 2 | 312 | 6.50% | $2,377,900.75 | $2,377,900.75 |
| | TURKEY UNIT 1 | 312 | 8.80% | $2,961,524.84 | $2,961,524.84 |
| | TURKEY UNIT 2 | 312 | 6.70% | $2,451,904.92 | $2,451,904.92 |
| | TOTAL FOR PROJECT 2 | | | $17,611,467.81 | $17,611,467.81 |
| 4 | CAPE CANAVERAL COMMON | 311 | 4.90% | $17,254.20 | $17,254.20 |
| | PT EVERGLADES COMMON | 311 | 5.80% | $19,812.30 | $19,812.30 |
| | TURKEY COMMON | 311 | 4.30% | $21,799.28 | $21,799.28 |
| | TOTAL FOR PROJECT 4 | | | $58,865.78 | $58,865.78 |
| 7 | ST. LUCIE UNIT 1 | 323 | 5.90% | $31,030.00 | $31,030.00 |
| | TOTAL FOR PROJECT 7 | | | $31,030.00 | $31,030.00 |
| 8 | MARTIN COMMON | 316 | 4.40% | $ 23,107.32 | $ 23,107.32 |
| | MARTIN COMMON | 316 | 7yr | $ 623,737.24 | $ 651,220.16 |
| | MARTIN COM PPBT | 316 | 5yr | $ 15,228.31 | $ 15,228.31 |
| | MARTIN COM PPBT | 316 | 7yr | $ 53,549.84 | $ - |
| | CAPE CANAVERAL FT | 316 | 7yr | $ - | $ 8,163.28 |
| | SANFORD | 316 | 7yr | $ 5,094.50 | $ 6,776.50 |
| | TURKEY COMMON | 316 | 7yr | $ 5,368.46 | $ 7,050.46 |
| | TURKEY UNIT 1 | 316 | 7yr | $ - | $ 1,159.18 |
| | PUTMAN COMMON | 346 | 7yr | $ - | $ 2,466.80 |
| | TOTAL FOR PROJECT 8 | | | 726,085.87 | 715,172.01 |
| 10 | ST. LUCIE COMMON | 321 | 3.20% | $117,793.83 | $117,793.83 |
| | TOTAL FOR PROJECT 10 | | | $117,793.83 | $117,793.83 |
| 12 | SCHERER COMMON | 310 | N/A | $9,936.72 | $9,936.72 |
| | SCHERER COMMON | 311 | 3.60% | $524,872.97 | $524,872.97 |
| | SCHERER COMMON | 312 | 5.30% | $328,761.62 | $328,761.62 |
| | SCHERER COMMON | 314 | 3.90% | $689.11 | $689.11 |
| | TOTAL FOR PROJECT 12 | | | $864,260.42 | $864,260.42 |
| 17 | MARTIN EQUIPM YAR | 394 | 7yr | $311,008.58 | $311,008.58 |
| | TOTAL FOR PROJECT 17 | | | $311,008.58 | $311,008.58 |
| 20 | CAPE CANAVERAL COMMON | 311 | 4.90% | $706,500.94 | $706,500.94 |
| | RIVIERA COMMON | 311 | 5.20% | $560,786.81 | $560,786.81 |
| | PT EVERGLADES COMMON | 311 | 5.80% | $296,707.34 | $296,707.34 |
| | TOTAL FOR PROJECT 20 | | | $1,563,995.09 | $1,563,995.09 |
| 21 | ST LUCIE COMMON | 321 | 3.20% | $796,190.00 | $828,789.00 |
| | TOTAL FOR PROJECT 21 | | | $796,190.00 | $828,789.00 |

PROJECT NO 3 b

FOR 2003

| PLANT NAME | PLANT ACCOUNT | DEPRECIATION RATE/ AMORTIZATION PERIOD | ACTUAL JANUARY PLANT IN SERVICE (BOM) | ACTUAL DECEMBER PLANT IN SERVICE (EOM) |
|---|---|---|---|---|
| CAPE CANAVERAL COMMON | 311 | 4.90% | $ 59,227.10 | $ 59,227.10 |
| CAPE CANAVERAL COMMON | 312 | 8.50% | $ 4,359.55 | $ 8,132.66 |
| CAPE CANAVERAL U1 | 312 | 6.60% | $ 484,171.51 | $ 494,606.87 |
| CAPE CANAVERAL U2 | 312 | 8.30% | $ 501,269.89 | $ 511,705.24 |
| CUTLER COMMON | 311 | 5.20% | $ 64,883.87 | $ 84,883.87 |
| CUTLER COMMON | 312 | 4.50% | $ 4,689.18 | $ 8,408.89 |
| CUTLER UNIT 5 | 312 | 5.00% | $ 302,030.62 | $ 312,722.43 |
| CUTLER UNIT 6 | 312 | 5.10% | $ 314,098.14 | $ 314,129.96 |
| FT LAUDERDALE COMMON | 341 | 5.30% | $ 58,859.79 | $ 58,859.79 |
| FT LAUDERDALE U4 | 343 | 6.50% | $ 440,440.80 | $ 441,333.87 |
| FT LAUDERDALE U5 | 343 | 6.80% | $ 448,440.37 | $ 448,731.41 |
| MANATEE COMMON | 312 | 4.60% | $ 13,378.02 | $ 9,359.98 |
| MANATEE UNIT 1 | 311 | 2.90% | $ 56,430.25 | $ 56,430.25 |
| MANATEE UNIT 1 | 312 | 4.00% | $ 473,304.93 | $ 472,570.03 |
| MANATEE UNIT 2 | 311 | 3.00% | $ 56,332.75 | $ 56,332.75 |
| MANATEE UNIT 2 | 312 | 4.20% | $ 509,404.20 | $ 508,734.38 |
| MARTIN COM FOSSIL | 312 | 4.60% | $ 4,850.00 | $ 10,093.81 |
| MARTIN UNIT 1 | 311 | 3.30% | $ 36,810.86 | $ 36,810.86 |
| MARTIN UNIT 1 | 312 | 4.60% | $ 521,075.17 | $ 521,075.17 |
| MARTIN UNIT 2 | 311 | 3.30% | $ 36,845.37 | $ 36,845.37 |
| MARTIN UNIT 2 | 312 | 4.90% | $ 519,484.96 | $ 519,484.96 |
| MARTIN UNIT 3 | 343 | 5.70% | $ 383,176.57 | $ 386,655.43 |
| MARTIN UNIT 4 | 343 | 5.50% | $ 377,207.01 | $ 380,685.87 |
| POWER RESCOU-JUNO | 391 | 3 yr amort | $ 10,284.15 | $ - |
| POWER RESCOU-JUNO | 394 | 7 yr amort | $ 38,826.87 | $ 38,826.87 |
| POWER RESCOU-JUNO | 395 | 7 yr amort | $ 473,947.53 | $ 473,947.53 |
| PT EVERGLADES COMMON | 311 | 5.80% | $ 127,911.34 | $ 127,911.34 |
| PT EVERGLADES COMMON | 312 | 7.70% | $ 6,624.33 | $ 19,111.95 |
| PT EVERGLADES UT1 | 312 | 6.10% | $ 453,408.32 | $ 453,661.22 |
| PT EVERGLADES UT2 | 312 | 6.50% | $ 474,860.48 | $ 475,113.36 |
| PT EVERGLADES UT3 | 312 | 7.80% | $ 503,843.57 | $ 503,968.62 |
| PT EVERGLADES UT4 | 312 | 6.40% | $ 512,009.55 | $ 512,809.90 |
| PUTNAM COMMON | 341 | 4.20% | $ 82,857.82 | $ 82,857.82 |
| PUTNAM COMMON | 343 | 5.60% | $ - | $ 3,138.97 |
| PUTNAM UNIT 1 | 343 | 6.00% | $ 330,024.01 | $ 330,105.26 |
| PUTNAM UNIT 2 | 343 | 6.30% | $ 342,873.31 | $ 363,508.78 |
| RIVIERA COMMON | 311 | 5.20% | $ 60,973.18 | $ 60,973.18 |
| RIVIERA COMMON | 312 | 8.90% | $ 4,889.18 | $ 8,166.97 |
| RIVIERA UNIT 3 | 312 | 8.90% | $ 438,874.32 | $ 449,392.38 |
| RIVIERA UNIT 4 | 312 | 7.90% | $ 422,903.90 | $ 433,421.96 |
| SANFORD COMMON | 343 | 11.60% | $ - | $ 5,188.21 |
| SANFORD UNIT 3 | 311 | 2.40% | $ 54,282.08 | $ 54,282.08 |
| SANFORD UNIT 3 | 312 | 2.40% | $ 76,028.32 | $ 98,147.67 |
| SANFORD UNIT 3 RL | 312 | 0.00% | $ 447,259.15 | $ 315,899.89 |
| SANFORD UNIT 4 RL | 312 | 2.60% | $ 41,859.48 | $ - |
| SANFORD UNIT 4 RL | 343 | 0.00% | $ - | $ 41,859.48 |
| SCHERER UNIT 4 | 312 | 4.50% | $ 537,039.34 | $ 537,039.34 |
| SJRPP COMMON | 311 | 3.40% | $ 43,193.33 | $ 43,193.33 |
| SJRPP COMMON | 312 | 3.70% | $ 66,188.18 | $ 66,188.18 |
| SJRPP UNIT 1 | 312 | 4.10% | $ 106,814.52 | $ 107,594.02 |
| SJRPP UNIT 2 | 312 | 4.20% | $ 106,783.43 | $ 107,562.94 |
| TURKEY COMMON | 311 | 4.30% | $ 59,056.19 | $ 59,056.19 |
| TURKEY COMMON | 312 | 6.90% | $ 4,889.20 | $ 8,168.05 |
| TURKEY UNIT 1 | 312 | 8.80% | $ 551,387.62 | $ 546,534.15 |
| TURKEY UNIT 2 | 312 | 8.70% | $ 505,398.92 | $ 505,638.44 |
| TOTAL FOR PROJECT 3 | | | $12,557,642.49 | $ 12,548,868.61 |

FOR 2003

**PROJECT NO. 5b**

| PLANT NAME | PLANT ACCOUNT | DEPRECIATION RATE | ACTUAL JANUARY PLANT IN SERVICE (BOM) | ACTUAL DECEMBER PLANT IN SERVICE (EOM) |
|---|---|---|---|---|
| CAPE CANAVERAL COMMON | 311 | 4.90% | $ 268,748.69 | $ 268,748.69 |
| CAPE CANAVERAL FT | 311 | 4.90% | $ 632,888.19 | $ 632,888.19 |
| FORT MYERS COMMON | 342 | 1.20% | $ 33,202.98 | $ 33,202.98 |
| FORT MYERS GAS TURBINE | 342 | 1.20% | $ 35,690.67 | $ 35,690.67 |
| FT LAUDERDALE COMMON | 342 | 4.30% | $ 898,110.65 | $ 898,110.65 |
| FT LAUDERDALE GTS | 342 | 0.70% | $ 584,290.23 | $ 584,290.23 |
| MANATEE COMMON | 311 | 3.50% | $ 30,323.73 | $ 30,323.73 |
| MANATEE COMMON | 312 | 4.60% | $ 174,543.23 | $ 174,543.23 |
| MANATEE FUEL OIL | 311 | 3.50% | $ 74,382.02 | $ 74,382.02 |
| MANATEE UNIT 1 | 312 | 4.00% | $ 104,845.35 | $ 104,845.35 |
| MANATEE UNIT 2 | 312 | 4.20% | $ 127,429.19 | $ 127,429.19 |
| MARTIN COM FOP | 311 | 3.60% | $ 65,092.76 | $ 65,092.76 |
| MARTIN COM FOSSIL | 311 | 3.60% | $ 407,224.94 | $ 407,224.94 |
| MARTIN COM PPBT | 311 | 3.60% | $ 638,132.62 | $ 638,132.62 |
| MARTIN UNIT 1 | 311 | 3.30% | $ 176,338.83 | $ 176,338.83 |
| PORT MANATEE TERM | 311 | 3.50% | $ 3,006,557.60 | $ 3,006,557.60 |
| PT EVERGLADES FOT | 311 | 5.80% | $ 1,132,078.22 | $ 1,132,078.22 |
| PT EVERGLADES GTU | 342 | 1.40% | $ 1,587,927.58 | $ 2,589,071.66 |
| PUTNAM COMMON | 342 | 4.00% | $ 749,025.94 | $ 749,025.94 |
| RIVIERA COMMON | 311 | 5.20% | $ 727,734.38 | $ 727,734.38 |
| SANFORD COMMON | 311 | 2.80% | $ 796,754.11 | $ - |
| SANFORD UNIT 3 | 311 | 2.40% | $ - | $ 796,754.11 |
| SJRPP COMMON | 311 | 3.40% | $ 42,091.24 | $ 42,091.24 |
| TURKEY COMMON | 311 | 4.30% | $ 87,560.23 | $ 87,560.23 |
| TURKEY UNIT 2 | 311 | 5.20% | $ 42,158.96 | $ 42,158.96 |
| **TOTAL FOR PROJECT 5** | | | **$ 12,423,132.34** | **$ 13,424,276.42** |
| POWER SUPPLY SUBSTATIONS | 352/361 | 2.20% | $0.00 | $ 1,682,237.16 |
| **TOTAL FOR PROJECT 23** | | | **$0.00** | **$ 1,682,237.16** |

# APPENDIX I

# ENVIRONMENTAL COST RECOVERY
# COMMISSION FORMS 42-1E THROUGH 42-8E

## JANUARY 2004 – DECEMBER 2004
## ESTIMATED/ACTUAL TRUE-UP

KMD-2
DOCKET NO. 040007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT _____
PAGES 1-47

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040007-EI EXHIBIT NO. 3
COMPANY/ F.P.+L.
WITNESS: K.M. Dubin (KMD-2)
DATE 11-08-04

Form 42-1E

**Florida Power & Light Company**
**Environmental Cost Recovery Clause**
**Calculation of the Estimated/Actual True-up**
**for the Period January through December 2004**

| Line No. | | |
|---|---|---|
| 1 | Over/(Under) Recovery for the Current Period (Form 42-2E, Page 2 of 2, Line 5) | ($109,412) |
| 2 | Interest Provision (Form 42-2E, Page 2 of 2, Line 6) | $5,619 |
| 3 | Sum of Current Period Adjustments (Form 42-2E, Page 2 of 2, Line 10) | $0 |
| 4 | Estimated/Actual True-up to be refunded/(recovered) in January through December 2005 | ($103,793) |

( ) Reflects Underrecovery

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2004

| Line No. | | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June |
|---|---|---|---|---|---|---|---|
| 1 | ECRC Revenues (net of Revenue Taxes) | $992,295 | $881,955 | $863,367 | $833,571 | $939,513 | $1,147,558 |
| 2 | True-up Provision (Order No. PSC-03-1348-FOF-EI) | 88,024 | 88,024 | 88,024 | 88,024 | 88,024 | 88,024 |
| 3 | ECRC Revenues Applicable to Period (Lines 1 + 2) | 1,080,318 | 969,978 | 951,391 | 921,595 | 1,027,537 | 1,235,582 |
| 4 | Jurisdictional ECRC Costs | | | | | | |
| | a - O&M Activities (Form 42-5A, Line 9) | 416,386 | 384,793 | 813,843 | 832,003 | 679,422 | 40,677 |
| | b - Capital Investment Projects (Form 42-7A, Line 9) | 481,592 | 507,896 | 514,185 | 530,862 | 558,303 | 582,739 |
| | c - Total Jurisdictional ECRC Costs | 897,978 | 892,689 | 1,328,028 | 1,362,865 | 1,237,725 | 623,416 |
| 5 | Over/(Under) Recovery (Line 3 - Line 4c) | 182,340 | 77,289 | (376,637) | (441,270) | (210,188) | 612,166 |
| 6 | Interest Provision (Form 42-3A, Line 10) | 999 | 997 | 779 | 383 | 38 | 155 |
| 7 | Est/Act True-Up for 2003 | 1,056,282 | 1,151,598 | 1,141,861 | 677,979 | 149,068 | (149,106) |
| | a - Deferred True-Up from 2003 (Form 42-1A, Line 7) | 43,877 | 43,877 | 43,877 | 43,877 | 43,877 | 43,877 |
| 8 | True-Up Collected /(Refunded) (See Line 2) | (88,024) | (88,024) | (88,024) | (88,024) | (88,024) | (88,024) |
| 9 | End of Period True-Up (Lines 5+6+7+7a+8) | 1,195,475 | 1,185,738 | 721,856 | 192,945 | (105,229) | 419,068 |
| 10 | Adjustments to Period Total True-Up Including Interest | | | | | | |
| 11 | End of Period Total Net True-Up (Lines 9+10) | $1,195,475 | $1,185,738 | $721,856 | $192,945 | ($105,229) | $419,068 |

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2004

| Line No. | | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|
| 1 | ECRC Revenues (net of Revenue Taxes) | $1,249,741 | $1,273,941 | $1,263,876 | $1,162,329 | $1,032,903 | $1,015,990 | $12,657,039 |
| 2 | True-up Provision (Order No. PSC-03-1348-FOF-EI) | 88,024 | 88,024 | 88,024 | 88,024 | 88,024 | 88,024 | 1,056,282 |
| 3 | ECRC Revenues Applicable to Period (Lines 1 + 2) | 1,337,764 | 1,361,964 | 1,351,899 | 1,250,352 | 1,120,927 | 1,104,014 | 13,713,321 |
| 4 | Jurisdictional ECRC Costs | | | | | | | |
| | a - O&M Activities (Form 42-5A, Line 9) | 661,177 | 597,243 | 544,075 | 389,623 | 429,085 | 449,277 | 6,237,604 |
| | b - Capital Investment Projects (Form 42-7A, Line 9) | 620,601 | 670,329 | 707,737 | 742,111 | 800,753 | 868,021 | 7,585,129 |
| | c - Total Jurisdictional ECRC Costs | 1,281,778 | 1,267,572 | 1,251,812 | 1,131,734 | 1,229,838 | 1,317,298 | 13,822,733 |
| 5 | Over/(Under) Recovery (Line 3 - Line 4c) | 55,986 | 94,392 | 100,087 | 118,618 | (108,911) | (213,284) | (109,412) |
| 6 | Interest Provision (Form 42-3A, Line 10) | 447 | 433 | 444 | 468 | 376 | 100 | 5,619 |
| 7 | Est/Act True-Up for 2003 | 375,191 | 343,601 | 350,403 | 362,911 | 393,974 | 197,415 | 1,056,282 |
| | a - Deferred True-Up from 2003 (Form 42-1A, Line 7) | 43,877 | 43,877 | 43,877 | 43,877 | 43,877 | 43,877 | 43,877 |
| 8 | True-Up Collected /(Refunded) (See Line 2) | (88,024) | (88,024) | (88,024) | (88,024) | (88,024) | (88,024) | (1,056,282) |
| 9 | End of Period True-Up (Lines 5+6+7+7a+8) | 387,478 | 394,280 | 406,788 | 437,851 | 241,292 | (59,916) | (59,916) |
| 10 | Adjustments to Period Total True-Up Including Interest | | | | | | | |
| 11 | End of Period Total Net True-Up (Lines 9+10) | $387,478 | $394,280 | $406,788 | $437,851 | $241,292 | ($59,916) | ($59,916) |

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2004

Interest Provision (In Dollars)

| Line No. | | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June |
|---|---|---|---|---|---|---|---|
| 1 | Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10) | $1,100,159 | $1,195,475 | $1,185,738 | $721,856 | $192,945 | ($105,229) |
| 2 | Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8) | 1,194,476 | 1,184,741 | 721,077 | 192,562 | (105,267) | 418,913 |
| 3 | Total of Beginning & Ending True-Up (Lines 1 + 2) | $2,294,635 | $2,380,216 | $1,906,815 | $914,418 | $87,678 | $313,684 |
| 4 | Average True-Up Amount (Line 3 x 1/2) | $1,147,318 | $1,190,108 | $953,408 | $457,209 | $43,839 | $156,842 |
| 5 | Interest Rate (First Day of Reporting Month) | 1.06000% | 1.03000% | 0.98000% | 0.98000% | 1.03000% | 1.04000% |
| 6 | Interest Rate (First Day of Subsequent Month) | 1.03000% | 0.98000% | 0.98000% | 1.03000% | 1.04000% | 1.33000% |
| 7 | Total of Beginning & Ending Interest Rates (Lines 5 + 6) | 2.09000% | 2.01000% | 1.96000% | 2.01000% | 2.07000% | 2.37000% |
| 8 | Average Interest Rate (Line 7 x 1/2) | 1.04500% | 1.00500% | 0.98000% | 1.00500% | 1.03500% | 1.18500% |
| 9 | Monthly Average Interest Rate (Line 8 x 1/12) | 0.08708% | 0.08375% | 0.08167% | 0.08375% | 0.08625% | 0.09875% |
| 10 | Interest Provision for the Month (Line 4 x Line 9) | $999 | $997 | $779 | $383 | $38 | $155 |

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2004

Interest Provision (in Dollars)

| Line No. | | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|
| 1 | Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10) | $419,068 | $387,478 | $394,280 | $406,788 | $437,851 | $241,292 | $6,577,701 |
| 2 | Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8) | 387,031 | 393,847 | 406,344 | 437,383 | 240,916 | (60,016) | 5,412,007 |
| 3 | Total of Beginning & Ending True-Up (Lines 1 + 2) | $806,099 | $781,325 | $800,624 | $844,171 | $678,767 | $181,276 | $11,989,708 |
| 4 | Average True-Up Amount (Line 3 x 1/2) | $403,050 | $390,663 | $400,312 | $422,086 | $339,384 | $90,638 | $5,994,854 |
| 5 | Interest Rate (First Day of Reporting Month) | 1.33000% | 1.33000% | 1.33000% | 1.33000% | 1.33000% | 1.33000% | N/A |
| 6 | Interest Rate (First Day of Subsequent Month) | 1.33000% | 1.33000% | 1.33000% | 1.33000% | 1.33000% | 1.33000% | N/A |
| 7 | Total of Beginning & Ending Interest Rates (Lines 5 + 6) | 2.66000% | 2.66000% | 2.66000% | 2.66000% | 2.66000% | 2.66000% | N/A |
| 8 | Average Interest Rate (Line 7 x 1/2) | 1.33000% | 1.33000% | 1.33000% | 1.33000% | 1.33000% | 1.33000% | N/A |
| 9 | Monthly Average Interest Rate (Line 8 x 1/12) | 0.11083% | 0.11083% | 0.11083% | 0.11083% | 0.11083% | 0.11083% | N/A |
| 10 | Interest Provision for the Month (Line 4 x Line 9) | $447 | $433 | $444 | $468 | $376 | $100 | $5,619 |

Form 42-4E

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
**January 2004 - December 2004**

Variance Report of O&M Activities
(in Dollars)

| Line | | (1) Estimated Actual | (2) Original Projections | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | |
| 1 | Air Operating Permit Fees-O&M | $1,872,726 | $2,061,980 | ($189,254) | -9.2% |
| 3a | Continuous Emission Monitoring Systems-O&M | $712,592 | $632,640 | $79,952 | 12.6% |
| 5a | Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M | $945,912 | $460,500 | $485,412 | 105.4% |
| 8a | Oil Spill Cleanup/Response Equipment-O&M | $166,037 | $165,996 | $41 | 0.0% |
| 13 | RCRA Corrective Action-O&M | $100,006 | $50,004 | $50,002 | 100.0% |
| 14 | NPDES Permit Fees-O&M | $142,807 | $134,205 | $8,602 | 6.4% |
| 17a | Disposal of Noncontainerized Liquid Waste-O&M | $285,633 | $288,000 | ($2,367) | -0.8% |
| 19a | Substation Pollutant Discharge Prevention & Removal - Distribution - O&M | $1,194,371 | $1,159,985 | $34,386 | 3.0% |
| 19b | Substation Pollutant Discharge Prevention & Removal - Transmission - O&M | $783,287 | $762,275 | $21,012 | 2.8% |
| 19c | Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates | ($560,232) | ($560,232) | $0 | 0.0% |
| 20 | Wastewater Discharge Elimination & Reuse | $10,000 | $50,000 | ($40,000) | -80.0% |
| NA | Amortization of Gains on Sales of Emissions Allowances | ($706,536) | ($430,356) | ($276,180) | 64.2% |
| 22 | Pipeline Integrity Management | $220,233 | $40,008 | $180,225 | 450.5% |
| 23 | SPCC-Spill Prevention, Control & Countermeasures | $185,429 | $250,000 | ($64,571) | -25.8% |
| 26 | UST Replacement/Removal | $148,050 | $148,050 | $0 | 0.0% |
| 27 | Lowest Quality Water Source | $301,830 | $370,200 | ($68,370) | -18.5% |
| 28 | CWA 316(b) Phase II Rule | $500,000 | $0 | $500,000 | 100.0% |
| 2 | Total O&M Activities | $6,302,145 | $5,583,255 | $718,890 | 12.9% |
| 3 | Recoverable Costs Allocated to Energy | $2,369,158 | $2,755,350 | ($386,192) | -14.0% |
| 4a | Recoverable Costs Allocated to CP Demand | $3,018,732 | $1,948,036 | $1,070,696 | 55.0% |
| 4b | Recoverable Costs Allocated to GCP Demand | $914,255 | $879,869 | $34,386 | 3.9% |

Notes:
Column(1) is the 12-Month Totals on Form 42-5E
Column(2) is the approved projected amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
**January 2004 - December 2004**

O&M Activities
(in Dollars)

| Line | | Actual JAN | Actual FEB | Actual MAR | Actual APR | Actual MAY | Actual JUN | 6-Month Sub-Total |
|---|---|---|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | | | | |
| 1 | Air Operating Permit Fees-O&M | $6,085 | ($19,597) | $461,979 | $158,022 | $158,715 | $158,022 | $923,226 |
| 3a | Continuous Emission Monitoring Systems-O&M | 30,927 | 26,399 | 154,753 | 31,289 | 27,666 | 47,776 | 318,810 |
| 5a | Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M | 0 | 0 | 0 | 113,708 | 103,804 | 8,520 | 226,032 |
| 8a | Oil Spill Cleanup/Response Equipment-O&M | 5,292 | 5,980 | 2,279 | 4,045 | 35,107 | 4,614 | 57,317 |
| 13 | RCRA Corrective Action-O&M | 3,933 | (359) | 0 | 1,632 | 0 | 0 | 5,206 |
| 14 | NPDES Permit Fees-O&M | 112,900 | 0 | 0 | 3,845 | 0 | 10,500 | 127,245 |
| 17a | Disposal of Noncontainerized Liquid Waste-O&M | 0 | 14,524 | 17,913 | 65,192 | 34,609 | (2,495) | 129,743 |
| 19a | Substation Pollutant Discharge Prevention & Removal - Distribution - O&M | 110,529 | 311,067 | 166,342 | 216,140 | 171,839 | 60,289 | 1,036,206 |
| 19b | Substation Pollutant Discharge Prevention & Removal - Transmission - O&M | 216,405 | 63,838 | 77,258 | 121,578 | 156,689 | 39,486 | 675,254 |
| 19c | Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates | (46,686) | (46,686) | (46,686) | (46,686) | (46,686) | (46,686) | (280,116) |
| 20 | Wastewater Discharge Elimination & Reuse | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NA | Amortization of Gains on Sales of Emissions Allowances | (18,429) | (18,429) | (18,429) | (18,429) | (18,429) | (261,123) | (353,268) |
| 21 | St. Lucie Turtle Net | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | Pipeline Integrity Management | (10,000) | 0 | 33 | 127,200 | 0 | 0 | 117,233 |
| 23 | SPCC - Spill Prevention, Control & Countermeasures | 9,320 | 2,167 | 6,839 | 22,564 | 42,481 | 2,058 | 85,429 |
| 26 | UST Replacement/Removal | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 27 | Lowest Quality Water Source | 0 | 47,037 | 0 | 39,618 | 20,075 | 19,711 | 126,441 |
| 28 | CWA 316(b) Phase II Rule | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | Total of O&M Activities | $ 420,276 | $ 385,941 | $ 822,281 | $ 839,718 | $ 685,870 | $ 40,672 | $ 3,194,758 |
| 3 | Recoverable Costs Allocated to Energy | $ 38,726 | $ 11,992 | $ 622,642 | $ 247,676 | $ 247,925 | $ (51,964) | $ 1,116,997 |
| 4a | Recoverable Costs Allocated to CP Demand | $ 294,364 | $ 86,225 | $ 56,640 | $ 399,245 | $ 289,449 | $ 55,690 | $ 1,181,613 |
| 4b | Recoverable Costs Allocated to GCP Demand | $ 87,186 | $ 287,724 | $ 142,999 | $ 192,797 | $ 148,496 | $ 36,946 | $ 896,148 |
| 5 | Retail Energy Jurisdictional Factor | 98.75007% | 98.75007% | 98.75007% | 98.75007% | 98.75007% | 98.75007% | |
| 6a | Retail CP Demand Jurisdictional Factor | 98.84301% | 98.84301% | 98.84301% | 98.84301% | 98.84301% | 98.84301% | |
| 6b | Retail GCP Demand Jurisdictional Factor | 100.00000% | 100.00000% | 100.00000% | 100.00000% | 100.00000% | 100.00000% | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | $ 38,242 | $ 11,842 | $ 614,860 | $ 244,580 | $ 244,826 | $ (51,315) | $ 1,103,035 |
| 8a | Jurisdictional CP Demand Recoverable Costs (B) | $ 290,958 | $ 85,227 | $ 55,984 | $ 394,626 | $ 286,100 | $ 55,046 | $ 1,167,941 |
| 8b | Jurisdictional GCP Demand Recoverable Costs (C) | $ 87,186 | $ 287,724 | $ 142,999 | $ 192,797 | $ 148,496 | $ 36,946 | $ 896,148 |
| 9 | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $ 416,386 | $ 384,793 | $ 813,843 | $ 832,003 | $ 679,422 | $ 40,677 | $ 3,167,124 |
| Notes: | | $ 416,386 | $ 384,793 | $ 813,843 | $ 832,003 | $ 679,422 | $ 40,677 | $ 3,167,124 |

(A) Line 3 x Line 5
(B) Line 4a x Line 6a
(C) Line 4b x Line 6b

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
**January 2004 - December 2004**

O&M Activities
(In Dollars)

| Line | | Estimated JUL | Estimated AUG | Estimated SEP | Estimated OCT | Estimated NOV | Estimated DEC | 6-Month Sub-Total | 12-Month Total | Method of Classification CP Demand | GCP Demand | Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | | | | | | | | |
| 1 | Air Operating Permit Fees-O&M | $158,000 | $158,300 | $158,300 | $158,300 | $158,300 | $158,300 | $949,500 | $1,872,726 | | | $1,872,726 |
| 3a | Continuous Emission Monitoring Systems-O&M | 168,860 | 43,898 | 43,908 | 43,918 | 49,998 | 43,200 | 393,782 | 712,592 | | | 712,592 |
| 5a | Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M | 162,500 | 162,500 | 153,500 | 80,460 | 80,460 | 80,460 | 719,880 | 945,912 | 945,912 | | |
| 8a | Oil Spill Cleanup/Response Equipment-O&M | 16,280 | 16,280 | 16,280 | 16,180 | 22,000 | 21,700 | 108,720 | 166,037 | | | 166,037 |
| 13 | RCRA Corrective Action-O&M | 15,800 | 15,800 | 15,800 | 15,800 | 15,800 | 15,800 | 94,800 | 100,006 | 100,006 | | |
| 14 | NPDES Permit Fees-O&M | 1,593 | 1,594 | 7,594 | 1,594 | 1,594 | 1,593 | 15,562 | 142,807 | 142,807 | | |
| 17a | Disposal of Noncontainerized Liquid Waste-O&M | 29,630 | 28,630 | 28,830 | 30,100 | 20,100 | 18,600 | 155,890 | 285,633 | | | 285,633 |
| 19a | Substation Pollutant Discharge Prevention & Removal - Distribution - O&M | 26,361 | 26,361 | 26,361 | 26,361 | 26,361 | 26,360 | 158,165 | 1,194,371 | | 1,194,371 | |
| 19b | Substation Pollutant Discharge Prevention & Removal - Transmission - O&M | 18,006 | 18,006 | 18,006 | 18,005 | 18,005 | 18,005 | 108,033 | 783,287 | 723,034 | | 60,253 |
| 19c | Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates | (46,686) | (46,686) | (46,686) | (46,686) | (46,686) | (46,686) | (280,116) | (560,232) | (258,569) | (280,116) | (21,547) |
| 20 | Wastewater Discharge Elimination & Reuse | 0 | 0 | 0 | 4,000 | 6,000 | 0 | 10,000 | 10,000 | 10,000 | | |
| NA | Amortization of Gains on Sales of Emissions Allowances | (58,878) | (58,878) | (58,878) | (58,878) | (58,878) | (58,878) | (353,268) | (706,536) | | | (706,536) |
| 22 | Pipeline Integrity Management | 34,000 | 34,000 | 35,000 | 0 | 0 | 0 | 103,000 | 220,233 | 220,233 | | |
| 23 | SPCC - Spill Prevention, Control & Countermeasures | 0 | 0 | 55,000 | 0 | 0 | 45,000 | 100,000 | 185,429 | 185,429 | | |
| 26 | UST Replacement/Removal | 40,000 | 40,000 | 0 | 0 | 34,025 | 34,025 | 148,050 | 148,050 | 148,050 | | |
| 27 | Lowest Quality Water Source | 25,430 | 25,430 | 25,430 | 33,033 | 33,033 | 33,033 | 175,389 | 301,830 | 301,830 | | |
| 28 | CWA 316(b) Phase II Rule | 78,280 | 139,140 | 72,140 | 72,140 | 74,140 | 64,160 | 500,000 | 500,000 | 500,000 | | |
| 2 | Total of O&M Activities | $ 669,176 | $ 604,375 | $ 550,585 | $ 394,327 | $ 434,252 | $ 454,672 | $ 3,107,387 | $ 6,302,145 | $ 3,018,732 | $ 914,255 | $2,369,158 |
| 3 | Recoverable Costs Allocated to Energy | $ 313,481 | $ 187,819 | $ 188,029 | $ 189,209 | $ 191,109 | $ 182,511 | $ 1,252,161 | $ 2,369,158 | | | |
| 4a | Recoverable Costs Allocated to CP Demand | $ 352,677 | $ 413,538 | $ 359,538 | $ 202,100 | $ 240,125 | $ 269,144 | $ 1,837,119 | $ 3,018,732 | | | |
| 4b | Recoverable Costs Allocated to GCP Demand | $ 3,018 | $ 3,018 | $ 3,018 | $ 3,018 | $ 3,018 | $ 3,017 | $ 18,107 | $ 914,255 | | | |
| 5 | Retail Energy Jurisdictional Factor | 98.75007% | 98.75007% | 98.75007% | 98.75007% | 98.75007% | 98.75007% | | | | | |
| 6a | Retail CP Demand Jurisdictional Factor | 98.84301% | 98.84301% | 98.84301% | 98.84301% | 98.84301% | 98.84301% | | | | | |
| 6b | Retail GCP Demand Jurisdictional Factor | 100.00000% | 100.00000% | 100.00000% | 100.00000% | 100.00000% | 100.00000% | | | | | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | $ 309,563 | $ 185,472 | $ 185,679 | $ 186,844 | $ 188,721 | $ 180,230 | $ 1,236,509 | $ 2,339,544 | | | |
| 8a | Jurisdictional CP Demand Recoverable Costs (B) | $ 348,596 | $ 408,753 | $ 355,378 | $ 199,761 | $ 237,346 | $ 266,030 | $ 1,815,864 | $ 2,983,805 | | | |
| 8b | Jurisdictional GCP Demand Recoverable Costs (C) | $ 3,018 | $ 3,018 | $ 3,018 | $ 3,018 | $ 3,018 | $ 3,017 | $ 18,107 | $ 914,255 | | | |
| 9 | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $ 661,177 | $ 597,243 | $ 544,075 | $ 389,623 | $ 429,085 | $ 449,277 | $ 3,070,480 | $ 6,237,604 | | | |

Notes:
(A) Line 3 x Line 5
(B) Line 4a x Line 6a
(C) Line 4b x Line 6b

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
**January 2004 - December 2004**

Variance Report of Capital Investment Projects-Recoverable Costs
(in Dollars)

| Line | | (1) Estimated Actual | (2) Original Projections | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1 | Description of Investment Projects | | | | |
| 2 | Low NOx Burner Technology-Capital | $ 1,922,081 | $ 1,932,576 | $ (10,495) | -0.5% |
| 3b | Continuous Emission Monitoring Systems-Capital | 1,423,157 | 1,469,791 | (46,634) | -3.2% |
| 4b | Clean Closure Equivalency-Capital | 5,773 | 5,795 | (22) | -0.4% |
| 5b | Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital | 1,522,889 | 1,621,408 | (98,519) | -6.1% |
| 7 | Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital | 3,175 | 3,189 | (14) | -0.4% |
| 8b | Oil Spill Cleanup/Response Equipment-Capital | 115,415 | 141,899 | (26,484) | -18.7% |
| 10 | Relocate Storm Water Runoff-Capital | 11,359 | 11,388 | (29) | -0.3% |
| NA | SO2 Allowances-Negative Return on Investment | (154,746) | (128,958) | (25,788) | 20.0% |
| 12 | Scherer Discharge Pipeline-Capital | 86,100 | 86,384 | (284) | -0.3% |
| 17b | Disposal of Noncontainerized Liquid Wate-Capital | 24,445 | 27,470 | (3,025) | -11.0% |
| 20 | Wastewater Discharge Elimination & Reuse | 196,836 | 276,043 | (79,207) | -28.7% |
| 21 | St. Lucie Turtle Net | 82,644 | 82,851 | (207) | -0.2% |
| 22 | Pipeline Integrity Management | 1,525 | 101,215 | (99,690) | -98.5% |
| 23 | SPCC-Spill Prevention, Control & Countermeasures | 966,964 | 1,343,066 | (376,102) | -28.0% |
| 24 | Manatee Reburn | 606,653 | 306,662 | 299,991 | 97.8% |
| 25 | Pt. Everglades ESP Technology | 864,245 | 1,092,984 | (228,739) | -20.9% |
| 2 | Total Investment Projects-Recoverable Costs | $ 7,678,515 | $ 8,373,763 | $ (695,248) | -8.3% |
| 3 | Recoverable Costs Allocated to Energy | $ 4,893,475 | $ 4,957,725 | $ (64,250) | -1.3% |
| 4 | Recoverable Costs Allocated to Demand | $ 2,785,040 | $ 3,416,038 | $ (630,998) | -18.5% |

Notes:
Column(1) is the 12-Month Totals on Form 42-7E
Column(2) is the approved projected amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
**January 2004 - December 2004**

Capital Investment Projects-Recoverable Costs
(in Dollars)

| Line | | Actual JAN | Actual FEB | Actual MAR | Actual APR | Actual MAY | Actual JUN | 6-Month Sub-Total |
|---|---|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects (A) | | | | | | | |
| 2 | Low NOx Burner Technology-Capital | $ 164,984 | $ 164,109 | $ 163,234 | $ 162,360 | $ 161,485 | $ 160,611 | $ 976,783 |
| 3b | Continuous Emission Monitoring Systems-Capital | 118,173 | 118,524 | 118,820 | 121,400 | 124,038 | 123,666 | 724,621 |
| 4b | Clean Closure Equivalency-Capital | 492 | 490 | 488 | 486 | 484 | 482 | 2,922 |
| 5b | Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital | 128,053 | 127,465 | 126,168 | 124,856 | 124,995 | 125,144 | 756,681 |
| 7 | Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital | 271 | 270 | 269 | 268 | 266 | 265 | 1,609 |
| 8b | Oil Spill Cleanup/Response Equipment-Capital | 10,371 | 9,362 | 10,093 | 10,030 | 9,966 | 9,903 | 59,725 |
| 10 | Relocate Storm Water Runoff-Capital | 960 | 958 | 955 | 953 | 950 | 948 | 5,724 |
| NA | SO2 Allowances-Negative Return on Investment | (11,711) | (11,568) | (11,424) | (11,280) | (13,915) | (15,604) | (75,502) |
| 12 | Scherer Discharge Pipeline-Capital | 7,305 | 7,281 | 7,258 | 7,234 | 7,210 | 7,187 | 43,475 |
| 17b | Disposal of Noncontainerized Liquid Waste-Capital | 3,838 | 3,810 | 3,782 | 3,753 | 3,724 | 3,696 | 22,603 |
| 20 | Wastewater Discharge Elimination &Reuse | 16,508 | 16,455 | 16,403 | 16,350 | 16,297 | 16,245 | 98,258 |
| 21 | St. Lucie Turtle Net | 6,982 | 6,965 | 6,947 | 6,930 | 6,913 | 6,896 | 41,633 |
| 22 | Pipeline Integrity Management | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 23 | SPCC - Spill Prevention, Control & Countermeasures | 26,154 | 36,889 | 39,959 | 45,298 | 58,790 | 70,505 | 277,595 |
| 24 | Manatee Rebum | 11,964 | 23,953 | 24,021 | 30,173 | 37,407 | 43,895 | 171,413 |
| 25 | Port Everglades ESP | 3,169 | 9,179 | 13,536 | 18,583 | 26,560 | 36,066 | 107,093 |
| 2 | Total Investment Projects - Recoverable Costs | $ 487,513 | $ 514,142 | $ 520,509 | $ 537,394 | $ 565,170 | $ 589,905 | $ 3,214,633 |
| 3 | Recoverable Costs Allocated to Energy | $ 302,035 | $ 320,347 | $ 324,519 | $ 337,864 | $ 353,236 | $ 367,193 | $ 2,005,195 |
| 4 | Recoverable Costs Allocated to Demand | $ 185,478 | $ 193,795 | $ 195,990 | $ 199,530 | $ 211,934 | $ 222,712 | $ 1,209,438 |
| 5 | Retail Energy Jurisdictional Factor | 98.75007% | 98.75007% | 98.75007% | 98.75007% | 98.75007% | 98.75007% | |
| 6 | Retail Demand Jurisdictional Factor | 98.84301% | 98.84301% | 98.84301% | 98.84301% | 98.84301% | 98.84301% | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | $ 298,260 | $ 316,343 | $ 320,463 | $ 333,640 | $ 348,821 | $ 362,604 | $ 1,980,131 |
| 8 | Jurisdictional Demand Recoverable Costs (C) | $ 183,332 | $ 191,553 | $ 193,722 | $ 197,222 | $ 209,482 | $ 220,135 | $ 1,195,446 |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $ 481,592 | $ 507,896 | $ 514,185 | $ 530,862 | $ 558,303 | $ 582,739 | $ 3,175,577 |

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
**January 2004 - December 2004**

Capital Investment Projects-Recoverable Costs
(in Dollars)

| Line | | Estimated JUL | Estimated AUG | Estimated SEP | Estimated OCT | Estimated NOV | Estimated DEC | 6-Month Sub-Total | 12-Month Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects (A) | | | | | | | | | | |
| 2 | Low NOx Burner Technology-Capital | $ 159,736 | $ 158,862 | $ 157,987 | $ 157,112 | $ 156,238 | $ 155,363 | $ 945,298 | $ 1,922,081 | | $ 1,922,081 |
| 3b | Continuous Emission Monitoring Systems-Capital | 119,834 | 116,634 | 116,209 | 115,785 | 115,286 | 114,788 | 698,536 | $ 1,423,157 | | 1,423,157 |
| 4b | Clean Closure Equivalency-Capital | 480 | 478 | 476 | 474 | 472 | 471 | 2,851 | $ 5,773 | 5,329 | 444 |
| 5b | Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital | 124,853 | 126,471 | 128,084 | 127,782 | 127,481 | 131,537 | 766,208 | $ 1,522,889 | 1,405,744 | 117,145 |
| 7 | Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital | 264 | 263 | 262 | 260 | 259 | 258 | 1,566 | $ 3,175 | 2,931 | 244 |
| 8b | Oil Spill Cleanup/Response Equipment-Capital | 9,467 | 9,035 | 8,978 | 8,921 | 9,404 | 9,885 | 55,690 | $ 115,415 | 106,537 | 8,878 |
| 10 | Relocate Storm Water Runoff-Capital | 945 | 943 | 940 | 938 | 936 | 933 | 5,635 | $ 11,359 | 10,485 | 874 |
| NA | SO2 Allowances-Negative Return on Investment | (14,356) | (13,896) | (13,437) | (12,978) | (12,518) | (12,059) | (79,244) | $ (154,746) | | (154,746) |
| 12 | Scherer Discharge Pipeline-Capital | 7,163 | 7,140 | 7,116 | 7,092 | 7,069 | 7,045 | 42,625 | $ 86,100 | 79,477 | 6,623 |
| 17b | Disposal of Noncontainerized Liquid Waste-Capital | 1,842 | 0 | 0 | 0 | 0 | 0 | 1,842 | $ 24,445 | 22,565 | 1,880 |
| 20 | Wastewater Discharge Elimination &Reuse | 16,192 | 16,139 | 16,087 | 16,034 | 15,981 | 18,145 | 98,578 | $ 196,836 | 181,695 | 15,141 |
| 21 | St. Lucie Turtle Net | 6,878 | 6,861 | 6,844 | 6,827 | 6,809 | 6,792 | 41,011 | $ 82,644 | 76,287 | 6,357 |
| 22 | Pipeline Integrity Management | 0 | 0 | 0 | 0 | 0 | 1,525 | 1,525 | $ 1,525 | 1,408 | 117 |
| 23 | SPCC - Spill Prevention, Control & Countermeasures | 86,765 | 104,681 | 108,078 | 109,686 | 129,969 | 150,190 | 689,369 | $ 966,964 | 892,582 | 74,382 |
| 24 | Manatee Rebum | 54,564 | 66,651 | 74,823 | 76,592 | 78,000 | 84,610 | 435,240 | $ 606,653 | | 606,653 |
| 25 | Port Everglades ESP | 53,608 | 78,315 | 104,007 | 136,738 | 175,243 | 209,241 | 757,152 | $ 864,245 | | 864,245 |
| 2 | Total Investment Projects - Recoverable Costs | $ 628,235 | $ 678,577 | $ 716,454 | $ 751,263 | $ 810,629 | $ 878,724 | $ 4,463,882 | $ 7,678,515 | $ 2,785,040 | $ 4,893,475 |
| 3 | Recoverable Costs Allocated to Energy | $ 392,990 | $ 427,490 | $ 460,886 | $ 494,635 | $ 535,201 | $ 577,080 | $ 2,888,282 | $ 4,893,475 | | |
| 4 | Recoverable Costs Allocated to Demand | $ 235,245 | $ 251,087 | $ 255,568 | $ 256,628 | $ 275,428 | $ 301,644 | $ 1,575,600 | $ 2,785,040 | | |
| 5 | Retail Energy Jurisdictional Factor | 98.75007% | 98.75007% | 98.75007% | 98.75007% | 98.75007% | 98.75007% | | | | |
| 6 | Retail Demand Jurisdictional Factor | 98.84301% | 98.84301% | 98.84301% | 98.84301% | 98.84301% | 98.84301% | | | | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | $ 388,078 | $ 422,147 | $ 455,126 | $ 488,452 | $ 528,512 | $ 569,867 | $ 2,852,182 | $ 4,832,313 | | |
| 8 | Jurisdictional Demand Recoverable Costs (C) | $ 232,523 | $ 248,182 | $ 252,611 | $ 253,659 | $ 272,241 | $ 298,154 | $ 1,557,370 | $ 2,752,816 | | |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $ 620,601 | $ 670,329 | $ 707,737 | $ 742,111 | $ 800,753 | $ 868,021 | $ 4,409,552 | $ 7,585,129 | | |

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 10,776,338 | 10,888,430 | 11,000,522 | 11,112,613 | 11,224,705 | 11,336,797 | 11,448,889 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $6,835,130 | $6,723,038 | $6,610,946 | $6,498,855 | $6,386,763 | $6,274,671 | $6,162,579 | n/a |
| 6. | Average Net Investment | | 6,779,084 | 6,666,992 | 6,554,900 | 6,442,809 | 6,330,717 | 6,218,625 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 40,177 | 39,513 | 38,848 | 38,184 | 37,520 | 36,855 | 231,097 |
| | b. Debt Component (Line 8 x 2.2507% x 1/12) | | 12,715 | 12,504 | 12,294 | 12,084 | 11,874 | 11,664 | 73,135 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 112,092 | 112,092 | 112,092 | 112,092 | 112,092 | 112,092 | 672,551 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $164,984 | $164,109 | $163,234 | $162,360 | $161,485 | $160,611 | $976,783 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 11,448,689 | 11,560,981 | 11,673,073 | 11,785,164 | 11,897,256 | 12,009,348 | 12,121,440 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $6,162,579 | $6,050,487 | $5,938,395 | $5,826,304 | $5,714,212 | $5,602,120 | $5,490,028 | n/a |
| 6. | Average Net Investment | | 6,106,533 | 5,994,441 | 5,882,350 | 5,770,258 | 5,658,166 | 5,546,074 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 36,191 | 35,527 | 34,862 | 34,198 | 33,534 | 32,869 | 438,278 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 11,453 | 11,243 | 11,033 | 10,823 | 10,612 | 10,402 | 138,701 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 112,092 | 112,092 | 112,092 | 112,092 | 112,092 | 112,092 | 1,345,102 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $159,738 | $158,862 | $157,987 | $157,112 | $156,238 | $155,363 | $1,922,081 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $19,424 | $97,932 | $40,261 | $466,269 | $55,721 | ($20,639) | $658,967 |
| | c. Retirements | | $4,850 | $17,260 | | $39,324 | $21,386 | $4,689 | $87,509 |
| | d. Other (A) | | | | | | | | $0 |
| 2. | Plant-In-Service/Depreciation Base (B) | $12,548,869 | 12,563,443 | 12,644,115 | 12,684,376 | 13,111,321 | 13,145,656 | 13,120,327 | 0 |
| 3. | Less: Accumulated Depreciation (C) | 5,594,282 | 5,655,813 | 5,705,347 | 5,772,420 | 5,801,301 | 5,849,257 | 5,913,944 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $6,954,587 | $6,907,630 | $6,938,768 | $6,911,956 | $7,310,020 | $7,296,398 | $7,206,383 | n/a |
| 6. | Average Net Investment | | 6,931,109 | 6,923,199 | 6,925,362 | 7,110,988 | 7,303,209 | 7,251,391 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | 39,324 | 41,078 | 41,031 | 41,044 | 42,144 | 43,283 | 42,976 | 251,556 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 13,000 | 12,985 | 12,989 | 13,337 | 13,698 | 13,601 | 79,610 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 66,381 | 66,794 | 67,073 | 68,205 | 69,343 | 69,375 | 407,171 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (2,286) | (2,286) | (2,286) | (2,286) | (2,286) | (2,286) | (13,716) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $118,172 | $118,524 | $118,820 | $121,400 | $124,038 | $123,666 | $724,621 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) Monthly depreciation offset for base rate retirements.

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $9,928 | | $15,000 | $0 | $0 | $0 | $683,895 |
| | c. Retirements | | | $512,774 | | | | | $600,283 |
| | d. Other (A) | | | | | | | | $0 |
| 2. | Plant-In-Service/Depreciation Base (B) | $13,120,327 | 13,130,255 | 12,617,481 | 12,632,481 | 12,632,481 | 12,632,481 | 12,632,481 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 5,913,944 | 5,980,527 | 5,531,607 | 5,595,476 | 5,659,359 | 5,723,243 | 5,787,127 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $7,206,383 | $7,149,728 | $7,085,874 | $7,037,005 | $6,973,121 | $6,909,238 | $6,845,354 | n/a |
| 6. | Average Net Investment | | 7,178,056 | 7,117,801 | 7,061,440 | 7,005,063 | 6,941,180 | 6,877,296 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 42,541 | 42,184 | 41,850 | 41,516 | 41,138 | 40,759 | 501,545 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 13,463 | 13,350 | 13,244 | 13,139 | 13,019 | 12,899 | 158,723 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 66,583 | 63,854 | 63,869 | 63,884 | 63,884 | 63,884 | 793,128 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (2,754) | (2,754) | (2,754) | (2,754) | (2,754) | (2,754) | (30,240) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $119,834 | $116,634 | $116,209 | $115,785 | $115,286 | $114,788 | $1,423,157 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) Monthly depreciation offset for base rate retirements.

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $58,866 | 58,866 | 58,866 | 58,866 | 58,866 | 58,866 | 58,866 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 27,058 | 27,302 | 27,547 | 27,791 | 28,035 | 28,280 | 28,524 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $31,808 | $31,564 | $31,319 | $31,075 | $30,831 | $30,586 | $30,342 | n/a |
| 6. | Average Net Investment | | 31,686 | 31,442 | 31,197 | 30,953 | 30,709 | 30,464 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 188 | 186 | 185 | 183 | 182 | 181 | 1,105 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 59 | 59 | 59 | 58 | 58 | 57 | 350 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 244 | 244 | 244 | 244 | 244 | 244 | 1,466 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $492 | $490 | $488 | $486 | $484 | $482 | $2,922 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $58,866 | 58,866 | 58,866 | 58,866 | 58,866 | 58,866 | 58,866 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 28,524 | 28,768 | 29,013 | 29,257 | 29,501 | 29,746 | 29,990 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $30,342 | $30,098 | $29,853 | $29,609 | $29,365 | $29,120 | $28,876 | n/a |
| 6. | Average Net Investment | | 30,220 | 29,976 | 29,731 | 29,487 | 29,243 | 28,998 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 179 | 178 | 176 | 175 | 173 | 172 | 2,158 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 57 | 56 | 56 | 55 | 55 | 54 | 683 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 244 | 244 | 244 | 244 | 244 | 244 | 2,932 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $480 | $476 | $476 | $474 | $472 | $471 | $5,773 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $1,666 | $1,074 | ($225,403) | ($2,364) | $97,934 | | ($127,093) |
| | c. Retirements | | $531,139 | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $13,424,276 | 12,894,803 | 12,895,877 | 12,670,474 | 12,668,111 | 12,766,044 | 12,766,044 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 1,827,009 | 1,333,580 | 1,370,983 | 1,408,256 | 1,445,396 | 1,482,592 | 1,519,846 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $11,597,267 | $11,561,223 | $11,524,894 | $11,262,218 | $11,222,714 | $11,283,452 | $11,246,199 | n/a |
| 6. | Average Net Investment | | 11,579,245 | 11,543,059 | 11,393,556 | 11,242,466 | 11,253,083 | 11,264,825 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 68,626 | 68,411 | 67,525 | 66,630 | 66,693 | 66,762 | 404,646 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 21,718 | 21,650 | 21,370 | 21,086 | 21,106 | 21,128 | 128,058 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 37,710 | 37,403 | 37,273 | 37,140 | 37,196 | 37,253 | 223,976 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $126,053 | $127,465 | $126,168 | $124,856 | $124,995 | $125,144 | $756,681 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $315,000 | $0 | $0 | $0 | $972,078 | $1,159,986 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $12,766,044 | 12,766,044 | 13,081,045 | 13,081,045 | 13,081,045 | 13,081,045 | 14,053,123 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 1,519,846 | 1,557,099 | 1,595,035 | 1,633,653 | 1,672,271 | 1,710,889 | 1,750,075 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $11,246,199 | $11,208,946 | $11,486,010 | $11,447,392 | $11,408,774 | $11,370,156 | $12,303,048 | n/a |
| 6. | Average Net Investment | | 11,227,572 | 11,347,478 | 11,466,701 | 11,428,083 | 11,389,465 | 11,836,602 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 66,541 | 67,252 | 67,959 | 67,730 | 67,501 | 70,151 | 811,780 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 21,058 | 21,283 | 21,507 | 21,434 | 21,362 | 22,201 | 256,903 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 37,253 | 37,936 | 38,618 | 38,618 | 38,618 | 39,185 | 454,205 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $124,853 | $126,471 | $128,084 | $127,782 | $127,481 | $131,537 | $1,522,889 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $31,030 | 31,030 | 31,030 | 31,030 | 31,030 | 31,030 | 31,030 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 15,748 | 15,901 | 16,053 | 16,206 | 16,358 | 16,511 | 16,663 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $15,282 | $15,129 | $14,977 | $14,824 | $14,672 | $14,519 | $14,367 | n/a |
| 8. | Average Net Investment | | 15,206 | 15,053 | 14,901 | 14,748 | 14,595 | 14,443 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 90 | 89 | 88 | 87 | 87 | 86 | 527 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 29 | 28 | 28 | 28 | 27 | 27 | 167 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 153 | 153 | 153 | 153 | 153 | 153 | 915 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $271 | $270 | $269 | $268 | $266 | $265 | $1,609 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $31,030 | 31,030 | 31,030 | 31,030 | 31,030 | 31,030 | 31,030 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 16,663 | 16,816 | 16,968 | 17,121 | 17,274 | 17,426 | 17,579 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $14,367 | $14,214 | $14,062 | $13,909 | $13,756 | $13,604 | $13,451 | n/a |
| 6. | Average Net Investment | | 14,290 | 14,138 | 13,985 | 13,833 | 13,680 | 13,528 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 85 | 84 | 83 | 82 | 81 | 80 | 1,022 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 27 | 27 | 26 | 26 | 26 | 25 | 323 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 153 | 153 | 153 | 153 | 153 | 153 | 1,831 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $264 | $263 | $262 | $260 | $259 | $258 | $3,175 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | ($7,889) | $0 | $0 | $0 | $0 | ($7,889) |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $715,172 | 715,172 | 707,283 | 707,283 | 707,283 | 707,283 | 707,283 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 435,987 | 444,212 | 451,519 | 459,848 | 467,777 | 475,907 | 484,036 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $279,185 | $270,960 | $255,764 | $247,635 | $239,506 | $231,376 | $223,247 | n/a |
| 6. | Average Net Investment | | 275,073 | 263,362 | 251,699 | 243,570 | 235,441 | 227,312 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 1,630 | 1,561 | 1,492 | 1,444 | 1,395 | 1,347 | 8,869 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 516 | 494 | 472 | 457 | 442 | 426 | 2,807 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 8,225 | 7,307 | 6,129 | 8,129 | 8,129 | 8,129 | 48,049 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $10,371 | $9,362 | $10,093 | $10,030 | $9,966 | $9,903 | $59,725 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $12,052 | | $0 | $0 | $54,948 | $0 | $59,111 |
| | c. Retirements | | | $86,208 | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $707,283 | 719,335 | 633,127 | 633,127 | 633,127 | 688,075 | 688,075 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 484,036 | 491,744 | 412,823 | 420,111 | 427,398 | 435,013 | 442,954 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $223,247 | $227,591 | $220,303 | $213,016 | $205,729 | $253,062 | $245,121 | n/a |
| 6. | Average Net Investment | | 225,419 | 223,947 | 216,660 | 209,372 | 229,395 | 249,091 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 1,336 | 1,327 | 1,284 | 1,241 | 1,360 | 1,476 | 16,893 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 423 | 420 | 406 | 393 | 430 | 467 | 5,346 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 7,708 | 7,287 | 7,287 | 7,287 | 7,614 | 7,942 | 93,175 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $9,467 | $9,035 | $8,978 | $8,921 | $9,404 | $9,885 | $115,415 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $117,794 | 117,794 | 117,794 | 117,794 | 117,794 | 117,794 | 117,794 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 34,850 | 35,164 | 35,478 | 35,792 | 36,106 | 36,421 | 36,735 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $82,944 | $82,630 | $82,316 | $82,002 | $81,688 | $81,373 | $81,059 | n/a |
| 6. | Average Net Investment | | 82,787 | 82,473 | 82,159 | 81,845 | 81,531 | 81,216 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 491 | 489 | 487 | 485 | 483 | 481 | 2,916 |
| | b. Debt Component (Line 8 x 2.2507% x 1/12) | | 155 | 155 | 154 | 154 | 153 | 152 | 923 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 314 | 314 | 314 | 314 | 314 | 314 | 1,885 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $960 | $958 | $955 | $953 | $950 | $948 | $5,724 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $117,794 | 117,794 | 117,794 | 117,794 | 117,794 | 117,794 | 117,794 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 36,735 | 37,049 | 37,363 | 37,677 | 37,991 | 36,305 | 38,619 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $81,059 | $80,745 | $80,431 | $80,117 | $79,803 | $79,489 | $79,175 | n/a |
| 6. | Average Net Investment | | 80,902 | 80,588 | 80,274 | 79,960 | 79,646 | 79,332 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 479 | 478 | 476 | 474 | 472 | 470 | 5,765 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 152 | 151 | 151 | 150 | 149 | 149 | 1,824 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 314 | 314 | 314 | 314 | 314 | 314 | 3,769 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $945 | $943 | $940 | $938 | $936 | $933 | $11,359 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $864,260 | 864,260 | 864,260 | 864,260 | 864,260 | 864,260 | 864,260 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 314,684 | 317,713 | 320,742 | 323,771 | 326,800 | 329,828 | 332,857 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $549,576 | $546,547 | $543,518 | $540,489 | $537,460 | $534,432 | $531,403 | n/a |
| 6. | Average Net Investment | | 548,062 | 545,033 | 542,004 | 538,975 | 535,946 | 532,917 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 3,248 | 3,230 | 3,212 | 3,194 | 3,176 | 3,158 | 19,220 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 1,028 | 1,022 | 1,017 | 1,011 | 1,005 | 1,000 | 6,082 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 3,029 | 3,029 | 3,029 | 3,029 | 3,029 | 3,029 | 18,173 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $7,305 | $7,281 | $7,258 | $7,234 | $7,210 | $7,187 | $43,475 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $864,260 | 864,260 | 864,260 | 864,260 | 864,260 | 864,260 | 864,260 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 332,857 | 335,886 | 338,915 | 341,944 | 344,973 | 348,002 | 351,031 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $531,403 | $528,374 | $525,345 | $522,318 | $519,287 | $516,258 | $513,229 | n/a |
| 6. | Average Net Investment | | 529,888 | 526,859 | 523,830 | 520,802 | 517,773 | 514,744 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 3,140 | 3,122 | 3,105 | 3,087 | 3,069 | 3,051 | 37,793 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 994 | 988 | 982 | 977 | 971 | 965 | 11,960 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 3,029 | 3,029 | 3,029 | 3,029 | 3,029 | 3,029 | 36,347 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $7,163 | $7,140 | $7,116 | $7,092 | $7,069 | $7,045 | $86,100 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $311,009 | 311,009 | 311,009 | 311,009 | 311,009 | 311,009 | 311,009 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 287,172 | 290,839 | 294,506 | 298,173 | 301,840 | 305,507 | 309,174 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $23,837 | $20,170 | $16,503 | $12,836 | $9,169 | $5,502 | $1,835 | n/a |
| 6. | Average Net Investment | | 22,004 | 18,337 | 14,670 | 11,003 | 7,336 | 3,669 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 130 | 109 | 87 | 65 | 43 | 22 | 456 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 41 | 34 | 28 | 21 | 14 | 7 | 144 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 3,667 | 3,667 | 3,667 | 3,667 | 3,667 | 3,667 | 22,002 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $3,839 | $3,810 | $3,781 | $3,753 | $3,724 | $3,696 | $22,603 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | $311,009 | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $311,009 | 311,009 | 0 | 0 | 0 | 0 | 0 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 309,174 | 311,009 | 0 | 0 | 0 | 0 | 0 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $1,835 | $0 | $0 | $0 | $0 | $0 | $0 | n/a |
| 6. | Average Net Investment | | 918 | 0 | 0 | 0 | 0 | 0 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 5 | 0 | 0 | 0 | 0 | 0 | 462 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 2 | 0 | 0 | 0 | 0 | 0 | 146 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 1,835 | 0 | 0 | 0 | 0 | 0 | 23,837 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $1,842 | $0 | $0 | $0 | $0 | $0 | $24,445 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 309,837 | 316,586 | 323,335 | 330,084 | 336,833 | 343,582 | 350,331 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $1,254,158 | $1,247,409 | $1,240,660 | $1,233,911 | $1,227,162 | $1,220,413 | $1,213,664 | n/a |
| 6. | Average Net Investment | | 1,250,784 | 1,244,035 | 1,237,286 | 1,230,537 | 1,223,788 | 1,217,039 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 7,413 | 7,373 | 7,333 | 7,293 | 7,253 | 7,213 | 43,877 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 2,346 | 2,333 | 2,321 | 2,308 | 2,295 | 2,283 | 13,886 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 6,749 | 6,749 | 6,749 | 6,749 | 6,749 | 6,749 | 40,494 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $16,508 | $16,455 | $16,403 | $16,350 | $16,297 | $16,245 | $98,258 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $375,000 | $375,000 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | 1,563,995 | 1,938,995 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $350,331 | 357,080 | 363,829 | 370,578 | 377,327 | 384,076 | 391,581 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $1,213,664 | $1,206,915 | $1,200,166 | $1,193,417 | $1,186,668 | $1,179,919 | $1,547,414 | n/a |
| 6. | Average Net Investment | | 1,210,290 | 1,203,541 | 1,196,792 | 1,190,043 | 1,183,294 | 1,363,666 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | Equity Component grossed up for taxes (D) | | 7,173 | 7,133 | 7,093 | 7,053 | 7,013 | 8,082 | 87,424 |
| | Debt Component (Line 6 x 2.2507% x 1/12) | | 2,270 | 2,257 | 2,245 | 2,232 | 2,219 | 2,558 | 27,667 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 6,749 | 6,749 | 6,749 | 6,749 | 6,749 | 7,505 | 81,744 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $16,192 | $16,139 | $18,087 | $16,034 | $15,981 | $18,145 | $196,836 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $828,789 | 828,789 | 828,789 | 828,789 | 828,789 | 828,789 | 828,789 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 29,743 | 31,953 | 34,163 | 36,373 | 38,583 | 40,794 | 43,004 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $799,046 | $796,836 | $794,626 | $792,416 | $790,206 | $787,996 | $785,785 | n/a |
| 6. | Average Net Investment | | 797,941 | 795,731 | 793,521 | 791,311 | 789,101 | 786,890 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 4,729 | 4,716 | 4,703 | 4,690 | 4,677 | 4,664 | 28,178 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 1,497 | 1,492 | 1,488 | 1,484 | 1,480 | 1,476 | 8,917 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 2,210 | 2,210 | 2,210 | 2,210 | 2,210 | 2,210 | 13,261 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (1,454) | (1,454) | (1,454) | (1,454) | (1,454) | (1,454) | (8,724) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $6,982 | $6,965 | $6,947 | $6,930 | $6,913 | $6,896 | $41,633 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) Depreciation offset for base rate items.

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $628,789 | 828,789 | 828,789 | 828,789 | 828,789 | 828,789 | 828,789 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $43,004 | 45,214 | 47,424 | 49,634 | 51,844 | 54,054 | 56,264 | n/a |
| 4. | CWIP - Non Interest Bearing | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $785,785 | $783,575 | $781,365 | $779,155 | $776,945 | $774,735 | $772,525 | n/a |
| 6. | Average Net Investment | | 784,680 | 782,470 | 780,260 | 778,050 | 775,840 | 773,630 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 4,650 | 4,637 | 4,624 | 4,611 | 4,598 | 4,585 | 55,884 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 1,472 | 1,468 | 1,463 | 1,459 | 1,455 | 1,451 | 17,686 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 2,210 | 2,210 | 2,210 | 2,210 | 2,210 | 2,210 | 26,521 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (1,454) | (1,454) | (1,454) | (1,454) | (1,454) | (1,454) | (17,448) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $6,878 | $6,861 | $6,844 | $6,827 | $6,809 | $6,792 | $82,644 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) Depreciation offset for base rate items.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | n/a |
| 6. | Average Net Investment | | 0 | 0 | 0 | 0 | 0 | 0 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | | | | | | | 0 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $250,000 | $250,000 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 0 | 0 | 250,000 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $0 | 0 | 0 | 0 | 0 | 0 | 552 | n/a |
| 4. | CWIP - Non Interest Bearing | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $0 | $0 | $0 | $0 | $0 | $0 | $249,448 | n/a |
| 6. | Average Net Investment | | 0 | 0 | 0 | 0 | 0 | 124,724 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 0 | 0 | 0 | 0 | 0 | 739 | 739 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 234 | 234 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | | | | | | 552 | 552 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $0 | $0 | $0 | $0 | $0 | $1,525 | $1,525 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $1,811,661 | $125,227 | $583,385 | $618,582 | $2,088,090 | $209,865 | $5,436,809 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | $752 | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $1,682,237 | 3,493,898 | 3,619,125 | 4,202,510 | 4,821,092 | 6,909,182 | 7,119,046 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 13,873 | 19,967 | 30,055 | 39,773 | 50,220 | 63,694 | 80,034 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $1,668,364 | $3,473,931 | $3,589,071 | $4,162,737 | $4,770,872 | $6,845,488 | $7,039,012 | n/a |
| 6. | Average Net Investment | | 2,571,147 | 3,531,501 | 3,875,904 | 4,466,805 | 5,808,180 | 6,942,250 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 15,238 | 20,930 | 22,971 | 26,473 | 34,423 | 41,144 | 161,179 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 4,822 | 6,624 | 7,270 | 8,378 | 10,894 | 13,021 | 51,008 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 6,094 | 9,335 | 9,718 | 10,447 | 13,473 | 16,341 | 65,409 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $26,154 | $36,889 | $39,959 | $45,298 | $58,790 | $70,505 | $277,595 |

**Notes:**

(A) Reserve Transfer in February.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $2,781,512 | $517,236 | $189,047 | $189,047 | $3,012,124 | $189,047 | $12,314,823 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $7,119,046 | 9,900,558 | 10,417,794 | 10,606,841 | 10,795,888 | 13,808,013 | 13,997,060 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $80,034 | 101,111 | 127,420 | 154,579 | 182,084 | 217,631 | 261,218 | n/a |
| 4. | CWIP - Non Interest Bearing | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $7,039,012 | $9,799,447 | $10,290,374 | $10,452,262 | $10,613,804 | $13,590,382 | $13,735,841 | n/a |
| 6. | Average Net Investment | | 8,419,230 | 10,044,911 | 10,371,318 | 10,533,033 | 12,102,093 | 13,663,112 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 49,897 | 59,532 | 61,467 | 62,425 | 71,724 | 80,976 | 547,200 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 15,791 | 18,840 | 19,452 | 19,756 | 22,698 | 25,626 | 173,172 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 21,077 | 26,309 | 27,159 | 27,505 | 35,546 | 43,588 | 246,593 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $86,765 | $104,681 | $108,078 | $109,686 | $129,969 | $150,190 | $966,964 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | $3,066,801 | $6,340 | $11,249 | $1,565,682 | $288,869 | $1,374,028 | $6,312,969 |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 3,066,801 | 3,073,142 | 3,084,390 | 4,650,072 | 4,938,941 | 6,312,969 | n/a |
| 5. | Net Investment (Lines 2 - 3 + 4) | $0 | $3,066,801 | $3,073,142 | $3,084,390 | $4,650,072 | $4,938,941 | $6,312,969 | n/a |
| 6. | Average Net Investment | | 1,533,401 | 3,069,971 | 3,078,766 | 3,867,231 | 4,794,507 | 5,625,955 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 9,088 | 18,195 | 18,247 | 22,920 | 28,415 | 33,343 | 130,206 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 2,876 | 5,758 | 5,774 | 7,253 | 8,992 | 10,552 | 41,206 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $11,964 | $23,952 | $24,021 | $30,173 | $37,408 | $43,895 | $171,413 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | $1,361,000 | $1,737,384 | $357,380 | $96,000 | $265,000 | $1,429,450 | $11,559,183 |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 4. | CWIP - Non Interest Bearing | $6,312,969 | 7,673,969 | 9,411,353 | 9,768,733 | 9,864,733 | 10,129,733 | 11,559,183 | n/a |
| 5. | Net Investment (Lines 2 - 3 + 4) | $6,312,969 | $7,673,969 | $9,411,353 | $9,768,733 | $9,864,733 | $10,129,733 | $11,559,183 | n/a |
| 6. | Average Net Investment | | 6,993,469 | 8,542,661 | 9,590,043 | 9,816,733 | 9,997,233 | 10,844,458 | n/a |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 41,448 | 50,629 | 56,836 | 58,180 | 59,250 | 64,271 | 460,820 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 13,117 | 16,022 | 17,987 | 18,412 | 18,751 | 20,340 | 145,835 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | $0 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $54,564 | $66,651 | $74,823 | $76,592 | $78,000 | $84,610 | $606,653 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | $812,293 | $728,404 | $388,274 | $905,673 | $1,139,180 | $1,297,468 | $5,271,292 |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | $0 |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 812,293 | 1,540,698 | 1,928,971 | 2,834,644 | 3,973,824 | 5,271,292 | n/a |
| 5. | Net Investment (Lines 2 - 3 + 4) | $0 | $812,293 | $1,540,698 | $1,928,971 | $2,834,644 | $3,973,824 | $5,271,292 | n/a |
| 6. | Average Net Investment | | 406,147 | 1,176,496 | 1,734,835 | 2,381,808 | 3,404,234 | 4,622,558 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 2,407 | 6,973 | 10,282 | 14,116 | 20,176 | 27,396 | 81,349 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 762 | 2,207 | 3,254 | 4,467 | 6,385 | 8,670 | 25,744 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | | | | | | | 0 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $3,169 | $9,179 | $13,536 | $18,583 | $26,560 | $36,066 | $107,093 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(In Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | $3,199,289 | $3,133,905 | $3,451,905 | $4,936,362 | $4,931,905 | $3,783,168 | $28,709,826 |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 4. | CWIP - Non Interest Bearing | $5,271,292 | 8,470,581 | 11,604,486 | 15,056,391 | 19,994,753 | 24,926,658 | 28,709,826 | n/a |
| 5. | Net Investment (Lines 2 - 3 + 4) | $5,271,292 | $8,470,581 | $11,604,486 | $15,056,391 | $19,994,753 | $24,926,658 | $28,709,826 | n/a |
| 6. | Average Net Investment | | 6,870,937 | 10,037,534 | 13,330,439 | 17,525,572 | 22,460,706 | 26,818,242 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 40,721 | 59,488 | 79,004 | 103,867 | 133,116 | 158,941 | $656,487 |
| | b. Debt Component (Line 6 x 2.2507% x 1/12) | | 12,887 | 18,826 | 25,002 | 32,871 | 42,127 | 50,300 | $207,757 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | | | | | | | |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $53,608 | $78,315 | $104,007 | $136,738 | $175,243 | $209,241 | $864,245 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8E, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Actual Period January through June 2004**

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(in Dollars)

| Line | | Beginning of Period Amount | January Actual | February Actual | March Actual | April Actual | May Actual | June Actual | End of Period Amount | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | |
| | a 158.100 Allowance Inventory | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| | b 158.200 Allowances Withheld | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| | c 182.300 Other Regulatory Assets-Losses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| | d 254.900 Other Regulatory Liabilities-Gains | (1,510,236) | (1,491,807) | (1,473,378) | (1,454,949) | (1,436,520) | (2,130,534) | (1,869,411) | | |
| 2 | Total Working Capital | ($1,510,236) | ($1,491,807) | ($1,473,378) | ($1,454,949) | ($1,436,520) | ($2,130,534) | ($1,869,411) | | |
| 3 | Average Net Working Capital Balance | | (1,501,021) | (1,482,592) | (1,464,163) | (1,445,734) | (1,783,527) | (1,999,973) | | |
| 4 | Return on Average Net Working Capital Balance | | | | | | | | | |
| | a Equity Component grossed up for taxes (A) | | (8,896) | (8,787) | (8,678) | (8,568) | (10,570) | (11,853) | (57,352) | |
| | b Debt Component (Line 6 x 2.2507% x 1/12) | | (2,815) | (2,781) | (2,746) | (2,712) | (3,345) | (3,751) | (18,150) | |
| 5 | Total Return Component | | ($11,711) | ($11,567) | ($11,424) | ($11,280) | ($13,915) | ($15,604) | ($75,502) | (D) |
| 6 | Expense Dr (Cr) | | | | | | | | | |
| | a 411.800 Gains from Dispositions of Allowances | | (18,429) | (18,429) | (18,429) | (18,429) | (18,429) | (261,123) | (353,268) | |
| | b 411.900 Losses from Dispositions of Allowances | | 0 | 0 | 0 | 0 | 0 | 0 | - | |
| | c 509.000 Allowance Expense | | 0 | 0 | 0 | 0 | 0 | 0 | - | |
| 7 | Net Expense (Lines 6a+6b+6c) | | ($18,429) | ($18,429) | ($18,429) | ($18,429) | ($18,429) | ($261,123) | ($353,268) | (E) |
| 8 | Total System Recoverable Expenses (Lines 5+7) | | (30,140) | (29,996) | (29,853) | (29,709) | (32,344) | (276,727) | | |
| | a Recoverable Costs Allocated to Energy | | (30,140) | (29,996) | (29,853) | (29,709) | (32,344) | (276,727) | | |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | | |
| 9 | Energy Jurisdictional Factor | | 98.53755% | 98.53755% | 98.53755% | 98.53755% | 98.53755% | 98.53755% | | |
| 10 | Demand Jurisdictional Factor | | 97.87297% | 97.87297% | 97.67297% | 97.87297% | 97.87297% | 97.87297% | | |
| 11 | Retail Energy-Related Recoverable Costs (B) | | (29,699) | (29,558) | (29,416) | (29,274) | (31,871) | (272,680) | (422,499) | |
| 12 | Retail Demand-Related Recoverable Costs (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 13 | Total Jurisdictional Recoverable Costs (Lines11+12) | | ($29,699) | ($29,558) | ($29,416) | ($29,274) | ($31,871) | ($272,680) | ($422,499) | |

**Notes:**

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Estimated Period July through December 2004**

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(in Dollars)

| Line | | Beginning of Period Amount | July Estimated | August Estimated | September Estimated | October Estimated | November Estimated | December Estimated | End of Period Amount | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | |
| | a 158.100 Allowance Inventory | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| | b 158.200 Allowances Withheld | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| | c 182.300 Other Regulatory Assets-Losses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| | d 254.900 Other Regulatory Liabilities-Gains | (1,869,411) | (1,810,533) | (1,751,655) | (1,692,777) | (1,633,899) | (1,575,021) | (1,516,143) | | |
| 2 | Total Working Capital | ($1,869,411) | ($1,810,533) | ($1,751,655) | ($1,692,777) | ($1,633,899) | ($1,575,021) | ($1,516,143) | | |
| 3 | Average Net Working Capital Balance | | (1,839,972) | (1,781,094) | (1,722,216) | (1,663,338) | (1,604,460) | (1,545,582) | | |
| 4 | Return on Average Net Working Capital Balance | | | | | | | | | |
| | a Equity Component grossed up for taxes (A) | | (10,905) | (10,556) | (10,207) | (9,858) | (9,509) | (9,160) | (117,548) | |
| | b Debt Component (Line 6 x 2.2507% x 1/12) | | (3,451) | (3,341) | (3,230) | (3,120) | (3,009) | (2,899) | (37,200) | |
| 5 | Total Return Component | | ($14,356) | ($13,896) | ($13,437) | ($12,978) | ($12,518) | ($12,059) | ($154,748) | (D) |
| 6 | Expense Dr (Cr) | | | | | | | | | |
| | a 411.800 Gains from Dispositions of Allowances | | (58,878) | (58,878) | (58,878) | (58,878) | (58,878) | (58,878) | (706,536) | |
| | b 411.900 Losses from Dispositions of Allowances | | 0 | 0 | 0 | 0 | 0 | 0 | - | |
| | c 509.000 Allowance Expense | | 0 | 0 | 0 | 0 | 0 | 0 | - | |
| 7 | Net Expense (Lines 6a+6b+6c) | | ($58,878) | ($58,878) | ($58,878) | ($58,878) | ($58,878) | ($58,878) | ($706,536) | (E) |
| 8 | Total System Recoverable Expenses (Lines 5+7) | | ($73,234) | ($72,774) | ($72,315) | ($71,856) | ($71,396) | ($70,937) | | |
| | a Recoverable Costs Allocated to Energy | | (73,234) | (72,774) | (72,315) | (71,856) | (71,396) | (70,937) | | |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | | |
| 9 | Energy Jurisdictional Factor | | 98.53755% | 98.53755% | 98.53755% | 98.53755% | 98.53755% | 98.53755% | | |
| 10 | Demand Jurisdictional Factor | | 97.87297% | 97.87297% | 97.87297% | 97.87297% | 97.87297% | 97.87297% | | |
| 11 | Retail Energy-Related Recoverable Costs (B) | | (72,163) | (71,710) | (71,257) | (70,805) | (70,352) | (69,899) | (848,686) | |
| 12 | Retail Demand-Related Recoverable Costs (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 13 | Total Jurisdictional Recoverable Costs (Lines11+12) | | ($72,163) | ($71,710) | ($71,257) | ($70,805) | ($70,352) | ($69,899) | ($848,686) | |

**Notes:**

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.3685% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding

| Project Number | Plant Name | Plant Account | Depreciation Rate / Amortization Period | Actual January Plant In Service (BOM) | Projected December Plant In Service (EOM) |
|---|---|---|---|---|---|
| **02 - Low NOX Burner Technology** | | | | | |
| | PtEverglades U1 | 312.0 | 6.10% | $2,700,574.97 | $2,700,574.97 |
| | PtEverglades U2 | 312.0 | 6.50% | $2,377,900.75 | $2,377,900.75 |
| | Riviera U3 | 312.0 | 8.90% | $3,846,591.65 | $3,846,591.65 |
| | Riviera U4 | 312.0 | 7.90% | $3,272,970.68 | $3,272,970.68 |
| | Turkey Pt U1 | 312.0 | 8.80% | $2,961,524.84 | $2,961,524.84 |
| | Turkey Pt U2 | 312.0 | 6.70% | $2,451,904.92 | $2,451,904.92 |
| | **Total For Project 02** | | | **$17,611,467.81** | **$17,611,467.81** |
| **03 - Continuous Emission Monitoring** | | | | | |
| | CapeCanaveral Comm | 311.0 | 4.90% | $59,227.10 | $59,227.10 |
| | CapeCanaveral Comm | 312.0 | 8.50% | $8,132.66 | $31,735.95 |
| | CapeCanaveral U1 | 312.0 | 8.80% | $494,606.87 | $494,606.87 |
| | CapeCanaveral U2 | 312.0 | 8.30% | $511,705.24 | $511,705.24 |
| | Cutler Comm | 311.0 | 5.20% | $64,883.87 | $64,883.87 |
| | Cutler Comm | 312.0 | 4.50% | $6,408.89 | $27,351.73 |
| | Cutler U5 | 312.0 | 5.00% | $312,722.43 | $312,722.43 |
| | Cutler U6 | 312.0 | 5.10% | $314,129.96 | $314,129.96 |
| | Manatee Comm | 312.0 | 4.60% | $9,359.98 | $31,859.00 |
| | Manatee U1 | 311.0 | 2.90% | $56,430.25 | $56,430.25 |
| | Manatee U1 | 312.0 | 4.00% | $472,570.03 | $472,570.03 |
| | Manatee U2 | 311.0 | 3.00% | $56,332.75 | $56,332.75 |
| | Manatee U2 | 312.0 | 4.20% | $508,734.36 | $508,734.36 |
| | Martin Comm | 312.0 | 4.60% | $10,093.81 | $31,631.74 |
| | Martin U1 | 311.0 | 3.30% | $36,810.86 | $36,810.86 |
| | Martin U1 | 312.0 | 4.80% | $521,075.17 | $521,075.17 |
| | Martin U2 | 311.0 | 3.30% | $36,845.37 | $36,845.37 |
| | Martin U2 | 312.0 | 4.90% | $519,484.96 | $519,484.96 |
| | PtEverglades Comm | 311.0 | 5.80% | $127,911.34 | $127,911.34 |
| | PtEverglades Comm | 312.0 | 7.70% | $19,111.95 | $61,620.47 |
| | PtEverglades U1 | 312.0 | 6.10% | $453,661.22 | $453,661.22 |
| | PtEverglades U2 | 312.0 | 6.50% | $475,113.36 | $475,113.36 |
| | PtEverglades U3 | 312.0 | 7.80% | $503,968.62 | $503,968.62 |
| | PtEverglades U4 | 312.0 | 8.40% | $512,809.90 | $512,809.90 |
| | Riviera Comm | 311.0 | 5.20% | $60,973.18 | $60,973.18 |
| | Riviera Comm | 312.0 | 8.90% | $8,166.97 | $29,117.75 |
| | Riviera U3 | 312.0 | 8.90% | $449,392.38 | $449,392.38 |
| | Riviera U4 | 312.0 | 7.90% | $433,421.96 | $433,421.96 |
| | Sanford U3 | 311.0 | 2.40% | $54,282.08 | $54,282.08 |
| | Sanford U3 | 312.0 | 2.40% | $98,147.67 | $131,944.80 |
| | Sanford U3 (Retiring | 312.0 | 0.00% | $315,699.69 | $315,699.69 |
| | Scherer U4 | 312.0 | 4.50% | $537,039.34 | $515,653.32 |
| | SJRPP - Comm | 311.0 | 3.40% | $43,193.33 | $43,193.33 |
| | SJRPP - Comm | 312.0 | 3.70% | $66,188.18 | $66,188.18 |
| | SJRPP U1 | 312.0 | 4.10% | $107,594.02 | $107,594.02 |
| | SJRPP U2 | 312.0 | 4.20% | $107,562.94 | $107,562.94 |
| | Turkey Pt Comm Fsil | 311.0 | 4.30% | $59,056.19 | $59,056.19 |
| | Turkey Pt Comm Fsil | 312.0 | 6.90% | $8,168.05 | $29,110.85 |
| | Turkey Pt U1 | 312.0 | 8.80% | $546,534.15 | $546,534.15 |
| | Turkey Pt U2 | 312.0 | 6.70% | $505,638.44 | $505,638.44 |
| | FtLauderdale Comm | 341.0 | 5.30% | $58,859.79 | $58,859.79 |
| | FtLauderdale Comm | 345.0 | 4.20% | $0.00 | $34,502.21 |
| | FtLauderdale U4 | 343.0 | 6.50% | $441,333.87 | $461,080.14 |
| | FtLauderdale U5 | 343.0 | 6.60% | $448,731.41 | $471,313.47 |
| | FtMyers U2 CC | 343.0 | 5.50% | $0.00 | $101,353.39 |
| | Martin U3 | 343.0 | 5.70% | $386,655.43 | $431,927.00 |

| Project Number | Plant Name | Plant Account | Depreciation Rate / Amortization Period | Actual January Plant In Service (BOM) | Projected December Plant In Service (EOM) |
|---|---|---|---|---|---|
| | Martin U4 | 343.0 | 5.50% | $380,685.87 | $421,026.31 |
| | Martin U8 | 343.0 | 5.50% | $0.00 | $25,657.00 |
| | Putnam Comm | 341.0 | 4.20% | $82,857.82 | $82,857.82 |
| | Putnam Comm | 343.0 | 5.60% | $3,138.97 | $3,138.97 |
| | Putnam U1 | 343.0 | 6.00% | $330,105.26 | $335,440.55 |
| | Putnam U2 | 343.0 | 6.30% | $363,508.78 | $368,844.07 |
| | Sanford Comm CC | 343.0 | 11.60% | $5,168.21 | $5,168.21 |
| | Sanford U4 | 343.0 | 5.50% | $41,859.48 | $41,859.48 |
| | Sanford U5 | 343.0 | 5.50% | $0.00 | $100,938.52 |
| | General Plant | 391.9 | 3Yr | $0.00 | $9,927.75 |
| | General Plant | 394.2 | 7Yr | $38,826.87 | $0.00 |
| | General Plant | 395.2 | 7Yr | $473,947.53 | $0.00 |
| | **Total For Project 03** | | | **$12,548,868.81** | **$12,632,480.49** |
| **04 - Clean Closure Equivalency Demonstration** | | | | | |
| | CapeCanaveral Comm | 311.0 | 4.90% | $17,254.20 | $17,254.20 |
| | PtEverglades Comm | 311.0 | 5.80% | $19,812.30 | $19,812.30 |
| | Turkey Pt Comm Fsil | 311.0 | 4.30% | $21,799.28 | $21,799.28 |
| | **Total For Project 04** | | | **$58,865.78** | **$58,865.78** |
| **05 - Maintenance of Above Ground Fuel Tanks** | | | | | |
| | CapeCanaveral Comm | 311.0 | 4.90% | $901,636.88 | $901,636.88 |
| | Manatee Comm | 311.0 | 3.50% | $3,111,263.35 | $3,111,263.35 |
| | Manatee Comm | 312.0 | 4.60% | $174,543.23 | $174,543.23 |
| | Manatee U1 | 312.0 | 4.00% | $104,845.35 | $104,845.35 |
| | Manatee U2 | 312.0 | 4.20% | $127,429.19 | $127,429.19 |
| | Martin Comm | 311.0 | 3.60% | $1,110,450.32 | $1,110,450.32 |
| | Martin U1 | 311.0 | 3.30% | $176,338.83 | $176,338.83 |
| | PtEverglades Comm | 311.0 | 5.80% | $1,132,078.22 | $1,132,078.22 |
| | Riviera Comm | 311.0 | 5.20% | $727,734.38 | $1,042,734.82 |
| | Sanford U3 | 311.0 | 2.40% | $796,754.11 | $796,754.11 |
| | SJRPP - Comm | 311.0 | 3.40% | $42,091.24 | $42,091.24 |
| | SJRPP - Comm | 312.0 | 3.70% | $0.00 | $2,292.39 |
| | Turkey Pt Comm Fsil | 311.0 | 4.30% | $87,560.23 | $87,560.23 |
| | Turkey Pt U2 | 311.0 | 5.20% | $42,158.96 | $42,158.96 |
| | FtLauderdale Comm | 342.0 | 4.30% | $898,110.65 | $898,110.65 |
| | FtLauderdale GTs | 342.0 | 0.70% | $584,290.23 | $584,290.23 |
| | FtMyers GTs | 342.0 | 1.20% | $68,893.65 | $68,893.65 |
| | PtEverglades GTs | 342.0 | 1.40% | $2,589,071.66 | $2,900,625.16 |
| | Putnam Comm | 342.0 | 4.00% | $749,025.94 | $749,025.94 |
| | **Total For Project 05** | | | **$13,424,276.42** | **$14,053,122.75** |
| **07 - Relocate Turbine Lube Oil Piping** | | | | | |
| | StLucie U1 | 323.0 | 5.90% | $31,030.00 | $31,030.00 |
| | **Total For Project 07** | | | **$31,030.00** | **$31,030.00** |
| **08 - Oil Spill Clean-up/Response Equipment** | | | | | |
| | CapeCanaveral Comm | 316.7 | 7Yr | $8,163.28 | $2,741.16 |
| | Martin Comm | 316.0 | 4.40% | $23,107.32 | $23,107.32 |
| | Martin Comm | 316.5 | 5Yr | $15,228.31 | $15,228.31 |
| | Martin Comm | 316.7 | 7Yr | $651,220.16 | $565,012.49 |
| | Sanford U3 | 316.7 | 7Yr | $6,776.50 | $6,776.50 |
| | Turkey Pt Comm Fsil | 316.7 | 7Yr | $7,050.46 | $7,050.46 |
| | Turkey Pt U1 | 316.7 | 7Yr | $1,159.18 | $1,159.18 |
| | FtMyers Common | 346.7 | 7Yr | $0.00 | $12,051.85 |
| | Putnam Comm | 346.7 | 7Yr | $2,466.80 | $0.00 |
| | Various Plants Common | 346.7 | 7Yr | $0.00 | $54,948.00 |
| | **Total For Project 08** | | | **$715,172.01** | **$688,075.27** |

| Project Number | Plant Name | Plant Account | Depreciation Rate / Amortization Period | Actual January Plant In Service (BOM) | Projected December Plant In Service (EOM) |
|---|---|---|---|---|---|
| **10 - Reroute Storm Water Runoff** | | | | | |
| | StLucie Comm | 321.0 | 3.20% | $117,793.83 | $117,793.83 |
| | **Total For Project 10** | | | **$117,793.83** | **$117,793.83** |
| **12 - Scherer Discharge Pipline** | | | | | |
| | Scherer Comm | 310.0 | 0.00% | $9,936.72 | $9,936.72 |
| | Scherer Comm | 311.0 | 3.60% | $524,872.97 | $524,872.97 |
| | Scherer Comm | 312.0 | 5.30% | $328,761.62 | $328,761.62 |
| | Scherer Comm | 314.0 | 3.90% | $689.11 | $689.11 |
| | **Total For Project 12** | | | **$864,260.42** | **$864,260.42** |
| **17 - Non-Contaminated Liquid Waste** | | | | | |
| | (Asset 30454503) | 394.2 | 7Yr | $311,008.58 | $0.00 |
| | **Total For Project 17** | | | **$311,008.58** | **$0.00** |
| **20 - Wastewater/Stormwater Discharge Elimination** | | | | | |
| | CapeCanaveral Comm | 311.0 | 4.90% | $706,500.94 | $856,500.94 |
| | Martin U1 | 312.0 | 4.80% | $0.00 | $225,000.00 |
| | Martin U2 | 312.0 | 4.90% | $0.00 | $0.00 |
| | PtEverglades Comm | 311.0 | 5.80% | $296,707.34 | $296,707.34 |
| | Riviera Comm | 311.0 | 5.20% | $560,786.81 | $560,786.81 |
| | **Total For Project 20** | | | **$1,563,995.09** | **$1,938,995.09** |
| **21 - St. Lucie Turtle Nets** | | | | | |
| | StLucie Comm | 321.0 | 3.20% | $828,789.34 | $828,789.34 |
| | **Total For Project 21** | | | **$828,789.34** | **$828,789.34** |
| **22 - Pipeline Integrity Management (PIM)** | | | | | |
| | Martin Comm | 311.0 | 3.60% | $0.00 | $0.00 |
| | FtLauderdale Comm | 341.0 | 5.30% | $0.00 | $250,000.00 |
| | **Total For Project 22** | | | **$0.00** | **$250,000.00** |
| **23 - Spill Prevention Clean-Up & Countermeasures** | | | | | |
| | CapeCanaveral Comm | 312.0 | 8.50% | $0.00 | $812,364.10 |
| | Cutler Comm | 312.0 | 4.50% | $0.00 | $88,115.33 |
| | Manatee Comm | 312.0 | 4.60% | $0.00 | $518,002.68 |
| | Martin Comm | 312.0 | 4.60% | $0.00 | $66,682.03 |
| | Riviera Common | 312.0 | 8.90% | $0.00 | $153,023.85 |
| | Riviera U3 | 312.0 | 8.90% | $0.00 | $757,398.09 |
| | Riviera U4 | 312.0 | 7.90% | $0.00 | $885,578.22 |
| | Sanford Common | 312.0 | 3.50% | $0.00 | $764,671.10 |
| | Turkey Pt Comm Fsil | 312.0 | 6.90% | $0.00 | $30,326.82 |
| | StLucie U1 | 324.0 | 3.20% | $0.00 | $0.00 |
| | FtLauderdale Comm | 342.0 | 4.30% | $0.00 | $1,252,502.81 |
| | FtLauderdale GTs | 342.0 | 0.70% | $0.00 | $553,266.61 |
| | FtMyers GTs | 342.0 | 1.20% | $0.00 | $855,065.85 |
| | PtEverglades GTs | 342.0 | 1.40% | $0.00 | $1,879,867.81 |
| | Putnam Comm | 342.0 | 4.00% | $0.00 | $1,816,787.37 |
| | Transmission | 352.0 | 2.20% | $480,747.84 | $891,327.74 |
| | Distributiion | 361.0 | 2.20% | $1,201,489.32 | $2,672,078.39 |
| | **Total For Project 23** | | | **$1,682,237.16** | **$13,997,058.80** |

# APPENDIX I

# ENVIRONMENTAL COST RECOVERY COMMISSION FORMS 42-1P THROUGH 42-7P

## JANUARY 2005 – DECEMBER 2005 PROJECTIONS

KMD-3
DOCKET NO. 040007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT _____
PAGES 1-75

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI EXHIBIT NO. 4
COMPANY/ F.P.&L.
WITNESS: K.M. Durbin (KMD-3)
DATE: 11-08-04

Form 42-1P

**Florida Power & Light Company**

Environmental Cost Recovery Clause

Total Jurisdictional Amount to Be Recovered

For the Projected Period

**January 2005 to December 2005**

| Line No. | | Energy ($) | CP Demand ($) | GCP Demand ($) | Total ($) |
|---|---|---|---|---|---|
| 1 | Total Jurisdictional Rev. Req. for the projected period | | | | |
| | a Projected O&M Activities (FORM 42-2P, Page 2 of 2, Lines 7 through 9) | 3,335,141 | 4,975,936 | 681,764 | 8,992,841 |
| | b Projected Capital Projects (FORM 42-3P, Page 2 of 2, Lines 7 through 9) | 11,027,258 | 4,456,733 | 0 | 15,483,991 |
| | c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b) | 14,362,399 | 9,432,669 | 681,764 | 24,476,832 |
| 2 | True-up for Estimated Over/(Under) Recovery for the current period January 2004 - December 2004 (FORM 42-1E, Line 4, filed on August 4, 2004) | (53,852) | (43,075) | (6,865) | (103,793) |
| 3 | Final True-up Over/(Under) for the period January 2003 - December 2003 (FORM 42-1A, Line 7, filed on April 1, 2004) | 26,983 | 12,640 | 4,254 | 43,877 |
| 4 | Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2005 - December 2005 (Line 1 - Line 2 - Line 3) | 14,389,268 | 9,463,104 | 684,375 | 24,536,748 |
| 5a | Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier 1.01597) | 14,619,065 | 9,614,230 | 695,304 | 24,928,600 |

Notes:

Allocation to energy and demand in each period are in proportion to the respective period split of costs.

True-up costs are split in proportion to the split of actual demand-related and energy-related costs from respective true-up periods.

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
**January 2005 - December 2005**

O&M Activities
(in Dollars)

| Line # | Project # | Projected JAN | Projected FEB | Projected MAR | Projected APR | Projected MAY | Projected JUN | 6-Month Sub-Total |
|---|---|---|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | | | | |
| | 1 Air Operating Permit Fees-O&M | $159,067 | $159,067 | $159,067 | $159,067 | $159,067 | $159,067 | $954,402 |
| | 3a Continuous Emission Monitoring Systems-O&M | 59,323 | 59,323 | 59,323 | 59,323 | 59,323 | 59,323 | 355,938 |
| | 5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M | 0 | 0 | 21,000 | 0 | 210,000 | 0 | 231,000 |
| | 8a Oil Spill Cleanup/Response Equipment-O&M | 13,833 | 13,833 | 13,833 | 13,833 | 13,833 | 13,833 | 82,998 |
| | 13 RCRA Corrective Action-O&M | 0 | 0 | 25,000 | 0 | 0 | 25,000 | 50,000 |
| | 14 NPDES Permit Fees-O&M | 156,400 | 0 | 0 | 0 | 0 | 0 | 156,400 |
| | 17a Disposal of Noncontainerized Liquid Waste-O&M | 19,667 | 19,667 | 38,667 | 19,000 | 29,667 | 10,667 | 137,335 |
| | 19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M | 112,676 | 109,722 | 89,221 | 115,482 | 83,301 | 59,432 | 569,834 |
| | 19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M | 113,716 | 110,722 | 84,721 | 119,782 | 88,101 | 68,232 | 585,274 |
| | 19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates | (46,686) | (46,686) | (46,686) | (46,686) | (46,686) | (46,686) | (280,116) |
| | 20 Wastewater Discharge Elimination &Reuse | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | NA Amortization of Gains on Sales of Emissions Allowances | (18,553) | (18,553) | (18,553) | (18,553) | (18,553) | (18,553) | (111,318) |
| | 22 Pipeline Integrity Management | 0 | 0 | 0 | 0 | 122,500 | 0 | 122,500 |
| | 23 SPCC - Spill Prevention, Control & Countermeasures | 22,404 | 22,404 | 20,000 | 0 | 0 | 20,000 | 84,808 |
| | 26 UST Replacement/Removal | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 27 Lowest Quality Water Source | 31,500 | 31,500 | 31,500 | 31,500 | 31,500 | 31,500 | 189,000 |
| | 28 CWA 316(b) Phase II Rule | 45,833 | 45,833 | 490,133 | 45,833 | 45,833 | 490,133 | 1,163,598 |
| | 29 SCR Consumables | 0 | 0 | 48,667 | 48,667 | 48,667 | 48,667 | 194,668 |
| 2 | Total of O&M Activities | $ 669,180 | $ 506,832 | $ 1,015,893 | $ 547,248 | $ 826,553 | $ 920,615 | $ 4,486,321 |
| 3 | Recoverable Costs Allocated to Energy | $ 240,289 | $ 240,058 | $ 305,725 | $ 288,755 | $ 296,985 | $ 276,457 | $ 1,648,270 |
| 4a | Recoverable Costs Allocated to CP Demand | $ 339,558 | $ 180,395 | $ 644,290 | $ 166,354 | $ 469,610 | $ 608,069 | $ 2,408,275 |
| 4b | Recoverable Costs Allocated to GCP Demand | $ 89,333 | $ 86,379 | $ 65,878 | $ 92,139 | $ 59,958 | $ 36,089 | $ 429,776 |
| 5 | Retail Energy Jurisdictional Factor | 98.56595% | 98.56595% | 98.56595% | 98.56595% | 98.56595% | 98.56595% | |
| 6a | Retail CP Demand Jurisdictional Factor | 98.63390% | 98.63390% | 98.63390% | 98.63390% | 98.63390% | 98.63390% | |
| 6b | Retail GCP Demand Jurisdictional Factor | 100.00000% | 100.00000% | 100.00000% | 100.00000% | 100.00000% | 100.00000% | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | $ 236,843 | $ 236,616 | $ 301,341 | $ 284,614 | $ 292,726 | $ 272,492 | $ 1,624,632 |
| 8a | Jurisdictional CP Demand Recoverable Costs (B) | $ 334,920 | $ 177,930 | $ 635,488 | $ 164,081 | $ 463,194 | $ 599,762 | $ 2,375,375 |
| 8b | Jurisdictional GCP Demand Recoverable Costs (C) | $ 89,333 | $ 86,379 | $ 65,878 | $ 92,139 | $ 59,958 | $ 36,089 | $ 429,776 |
| 9 | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $ 661,096 | $ 500,925 | $ 1,002,707 | $ 540,834 | $ 815,878 | $ 908,343 | $ 4,429,783 |

Notes:
(A) Line 3 x Line 5
(B) Line 4a x Line 6a
(C) Line 4b x Line 6b

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
**January 2005 - December 2005**

O&M Activities
(in Dollars)

| Line # | Project # | Projected JUL | Projected AUG | Projected SEP | Projected OCT | Projected NOV | Projected DEC | 6-Month Sub-Total | 12-Month Total | Method of Classification: CP Demand | Method of Classification: GCP Demand | Method of Classification: Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | | | | | | | | |
| | 1 Air Operating Permit Fees-O&M | $159,067 | $159,067 | $159,067 | $159,067 | $159,067 | $159,067 | $954,402 | $1,908,804 | | | $1,908,804 |
| | 3a Continuous Emission Monitoring Systems-O&M | 59,323 | 59,323 | 59,323 | 59,323 | 59,323 | 59,323 | 355,938 | 711,876 | | | 711,876 |
| | 5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M | 217,000 | 0 | 0 | 0 | 0 | 0 | 217,000 | 448,000 | 448,000 | | |
| | 8a Oil Spill Cleanup/Response Equipment-O&M | 13,833 | 13,833 | 13,833 | 13,833 | 13,833 | 13,833 | 82,998 | 165,996 | | | 165,996 |
| | 13 RCRA Corrective Action-O&M | 0 | 0 | 25,000 | 0 | 0 | 25,000 | 50,000 | 100,000 | 100,000 | | |
| | 14 NPDES Permit Fees-O&M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 156,400 | 156,400 | | |
| | 17a Disposal of Noncontainerized Liquid Waste-O&M | 21,667 | 22,000 | 29,333 | 29,333 | 18,333 | 11,000 | 131,666 | 269,001 | | | 269,001 |
| | 19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M | 62,701 | 62,677 | 62,601 | 66,882 | 72,716 | 64,469 | 392,046 | 961,880 | | 961,880 | |
| | 19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M | 71,501 | 71,477 | 79,651 | 108,182 | 84,716 | 110,719 | 526,246 | 1,111,520 | 1,026,018 | | 85,502 |
| | 19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates | (46,686) | (46,686) | (46,686) | (46,686) | (46,686) | (46,686) | (280,118) | (560,232) | (258,569) | (280,116) | (21,547) |
| | 20 Wastewater Discharge Elimination & Reuse | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| | NA Amortization of Gains on Sales of Emissions Allowances | (18,553) | (18,553) | (18,553) | (18,553) | (18,553) | (18,553) | (111,318) | (222,636) | | | (222,636) |
| | 22 Pipeline Integrity Management | 52,500 | 0 | 0 | 0 | 0 | 0 | 52,500 | 175,000 | 175,000 | | |
| | 23 SPCC - Spill Prevention, Control & Countermeasures | 0 | 0 | 20,000 | 0 | 0 | 20,000 | 40,000 | 124,808 | 124,808 | | |
| | 26 UST Replacement/Removal | 0 | 0 | 284,000 | 0 | 0 | 284,000 | 568,000 | 568,000 | 568,000 | | |
| | 27 Lowest Quality Water Source | 31,500 | 31,500 | 31,500 | 31,500 | 31,500 | 31,500 | 189,000 | 378,000 | 378,000 | | |
| | 28 CWA 316(b) Phase II Rule | 45,833 | 45,833 | 490,133 | 45,633 | 45,833 | 490,133 | 1,163,598 | 2,327,196 | 2,327,196 | | |
| | 29 SCR Consumables | 48,667 | 48,667 | 48,667 | 48,667 | 48,667 | 48,667 | 292,002 | 486,670 | | | 486,670 |
| 2 | Total of O&M Activities | $ 718,353 | $ 449,138 | $1,237,869 | $ 497,381 | $ 468,749 | $1,252,472 | $ 4,623,962 | $ 9,110,283 | $ 5,044,853 | $ 681,764 | $3,383,666 |
| 3 | Recoverable Costs Allocated to Energy | $ 287,708 | $ 288,040 | $ 296,001 | $ 298,196 | $ 285,391 | $ 280,058 | $ 1,735,395 | $ 3,383,666 | | | |
| 4a | Recoverable Costs Allocated to CP Demand | $ 391,287 | $ 121,764 | $ 902,610 | $ 155,646 | $ 133,985 | $ 931,268 | $ 2,636,579 | $ 5,044,853 | | | |
| 4b | Recoverable Costs Allocated to GCP Demand | $ 39,358 | $ 39,334 | $ 39,258 | $ 43,539 | $ 49,373 | $ 41,126 | $ 251,988 | $ 681,764 | | | |
| 5 | Retail Energy Jurisdictional Factor | 98.56595% | 98.56595% | 98.56595% | 98.56595% | 98.56595% | 98.56595% | | | | | |
| 6a | Retail CP Demand Jurisdictional Factor | 98.63390% | 98.63390% | 98.63390% | 98.63390% | 98.63390% | 98.63390% | | | | | |
| 6b | Retail GCP Demand Jurisdictional Factor | 100.00000% | 100.00000% | 100.00000% | 100.00000% | 100.00000% | 100.00000% | | | | | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | $ 283,583 | $ 283,909 | $ 291,757 | $ 293,920 | $ 281,298 | $ 276,042 | $ 1,710,509 | $ 3,335,141 | | | |
| 8a | Jurisdictional CP Demand Recoverable Costs (B) | $ 385,941 | $ 120,101 | $ 890,279 | $ 153,520 | $ 132,155 | $ 918,565 | $ 2,600,561 | $ 4,975,936 | | | |
| 6b | Jurisdictional GCP Demand Recoverable Costs (C) | $ 39,358 | $ 39,334 | $ 39,258 | $ 43,539 | $ 49,373 | $ 41,126 | $ 251,988 | $ 681,764 | | | |
| 9 | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $ 708,882 | $ 443,344 | $1,221,294 | $ 490,979 | $ 462,826 | $1,235,733 | $ 4,563,058 | $ 8,992,841 | | | |

Notes:
(A) Line 3 x Line 5
(B) Line 4a x Line 6a
(C) Line 4b x Line 6b

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
**January 2005 - December 2005**

Capital Investment Projects-Recoverable Costs
(in Dollars)

| Line # | Project # | Projected JAN | Projected FEB | Projected MAR | Projected APR | Projected MAY | Projected JUN | 6-Month Sub-Total |
|---|---|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects (A) | | | | | | | |
| 2 | Low NOx Burner Technology-Capital | $ 165,304 | $ 164,207 | $ 163,109 | $ 162,011 | $ 160,914 | $ 159,816 | $ 975,361 |
| 3b | Continuous Emission Monitoring Systems-Capital | 128,497 | 128,233 | 128,198 | 127,977 | 127,498 | 127,349 | 767,752 |
| 4b | Clean Closure Equivalency-Capital | 526 | 524 | 521 | 519 | 516 | 514 | 3,120 |
| 5b | Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital | 159,395 | 159,006 | 158,617 | 158,227 | 157,838 | 157,449 | 950,532 |
| 7 | Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital | 284 | 282 | 281 | 279 | 278 | 276 | 1,680 |
| 8b | Oil Spill Cleanup/Response Equipment-Capital | 10,303 | 10,225 | 10,147 | 10,070 | 9,992 | 10,996 | 61,733 |
| 10 | Relocate Storm Water Runoff-Capital | 1,088 | 1,085 | 1,082 | 1,079 | 1,076 | 1,073 | 6,483 |
| NA | SO2 Allowances-Negative Return on Investment | (14,756) | (14,574) | (14,393) | (14,211) | (17,492) | (20,773) | (96,199) |
| 12 | Scherer Discharge Pipeline-Capital | 8,040 | 8,010 | 7,981 | 7,951 | 7,921 | 7,892 | 47,795 |
| 17b | Disposal of Noncontainerized Liquid Waste-Capital | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | Wastewater Discharge Elimination &Reuse | 23,374 | 23,293 | 23,212 | 23,132 | 23,051 | 22,970 | 139,032 |
| 21 | St. Lucie Turtle Net | 8,310 | 8,289 | 8,267 | 8,245 | 8,224 | 8,202 | 49,537 |
| 22 | Pipeline Integrity Management | 3,541 | 3,531 | 3,520 | 3,509 | 3,498 | 3,487 | 21,086 |
| 23 | SPCC - Spill Prevention, Control & Countermeasures | 179,029 | 180,545 | 182,056 | 183,565 | 185,071 | 189,685 | 1,099,951 |
| 24 | Manatee Reburn | 114,607 | 123,819 | 131,629 | 139,316 | 147,003 | 147,023 | 803,397 |
| 25 | Pt. Everglades ESP Technology | 292,810 | 314,320 | 375,909 | 429,764 | 437,877 | 450,886 | 2,301,566 |
| 2 | Total Investment Projects - Recoverable Costs | $ 1,080,352 | $ 1,110,795 | $ 1,180,136 | $ 1,241,433 | $ 1,253,265 | $ 1,266,845 | $ 7,132,826 |
| 3 | Recoverable Costs Allocated to Energy | $ 716,761 | $ 746,373 | $ 814,889 | $ 875,363 | $ 886,374 | $ 895,266 | $ 4,935,027 |
| 4 | Recoverable Costs Allocated to Demand | $ 363,591 | $ 364,422 | $ 365,247 | $ 366,070 | $ 366,891 | $ 371,579 | $ 2,197,799 |
| 5 | Retail Energy Jurisdictional Factor | 98.56595% | 98.56595% | 98.56595% | 98.56595% | 98.56595% | 98.56595% | |
| 6 | Retail Demand Jurisdictional Factor | 98.63390% | 98.63390% | 98.63390% | 98.63390% | 98.63390% | 98.63390% | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | $ 706,483 | $ 735,670 | $ 803,203 | $ 862,810 | $ 873,663 | $ 882,427 | $ 4,864,256 |
| 8 | Jurisdictional Demand Recoverable Costs (C) | $ 358,624 | $ 359,443 | $ 360,257 | $ 361,069 | $ 361,879 | $ 366,503 | $ 2,167,775 |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $ 1,065,107 | $ 1,095,113 | $ 1,163,460 | $ 1,223,879 | $ 1,235,542 | $ 1,248,930 | $ 7,032,031 |

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

**Florida Power & Light Company**
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
**January 2005 - December 2005**

Capital Investment Projects-Recoverable Costs
(in Dollars)

| Line # | Project # | Projected JUL | Projected AUG | Projected SEP | Projected OCT | Projected NOV | Projected DEC | 6-Month Sub-Total | 12-Month Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects (A) | | | | | | | | | | |
| 2 | Low NOx Burner Technology-Capital | $ 158,718 | $ 157,621 | $ 156,523 | $ 155,425 | $ 154,328 | $ 153,230 | $ 935,845 | $ 1,911,206 | | $ 1,911,206 |
| 3b | Continuous Emission Monitoring Systems-Capital | 126,578 | 126,036 | 125,494 | 125,504 | 125,847 | 125,541 | 755,000 | $ 1,522,752 | | 1,522,752 |
| 4b | Clean Closure Equivalency-Capital | 512 | 509 | 507 | 504 | 502 | 500 | 3,034 | $ 6,154 | 5,681 | 473 |
| 5b | Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital | 157,060 | 156,670 | 156,281 | 155,892 | 155,502 | 155,113 | 936,518 | $ 1,887,050 | 1,741,892 | 145,158 |
| 7 | Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital | 275 | 273 | 272 | 270 | 269 | 267 | 1,626 | $ 3,306 | 3,052 | 254 |
| 8b | Oil Spill Cleanup/Response Equipment-Capital | 11,994 | 11,905 | 11,816 | 11,726 | 11,637 | 12,272 | 71,350 | $ 133,083 | 122,846 | 10,237 |
| 10 | Relocate Storm Water Runoff-Capital | 1,069 | 1,066 | 1,063 | 1,060 | 1,057 | 1,054 | 6,369 | $ 12,852 | 11,863 | 989 |
| NA | SO2 Allowances-Negative Return on Investment | (20,591) | (20,409) | (20,227) | (20,046) | (19,864) | (19,682) | (120,819) | $ (217,018) | | (217,018) |
| 12 | Scherer Discharge Pipeline-Capital | 7,862 | 7,832 | 7,803 | 7,773 | 7,743 | 7,714 | 46,727 | $ 94,522 | 87,251 | 7,271 |
| 17b | Disposal of Noncontainerized Liquid Waste-Capital | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $ - | 0 | 0 |
| 20 | Wastewater Discharge Elimination &Reuse | 22,889 | 22,808 | 22,727 | 22,646 | 22,565 | 24,216 | 137,851 | $ 276,883 | 255,584 | 21,299 |
| 21 | St. Lucie Turtle Net | 8,180 | 8,159 | 8,137 | 8,115 | 8,094 | 8,072 | 48,757 | $ 98,294 | 90,733 | 7,561 |
| 22 | Pipeline Integrity Management | 3,477 | 3,466 | 11,076 | 18,669 | 18,623 | 18,577 | 73,888 | $ 94,974 | 87,668 | 7,306 |
| 23 | SPCC - Spill Prevention, Control & Countermeasures | 194,289 | 195,773 | 197,253 | 198,731 | 200,206 | 201,677 | 1,187,929 | $ 2,287,880 | 2,111,889 | 175,991 |
| 24 | Manatee Rebum | 147,052 | 151,498 | 159,305 | 169,697 | 182,001 | 239,964 | 1,049,517 | $ 1,852,914 | | 1,852,914 |
| 25 | Pt. Everglades ESP Technology | 466,958 | 488,897 | 512,438 | 587,403 | 670,622 | 713,419 | 3,439,737 | $ 5,741,303 | | 5,741,303 |
| 2 | Total Investment Projects - Recoverable Costs | $ 1,286,322 | $ 1,312,104 | $ 1,350,468 | $ 1,443,369 | $ 1,539,132 | $ 1,641,934 | $ 8,573,329 | $ 15,706,155 | $ 4,518,459 | $ 11,187,696 |
| 3 | Recoverable Costs Allocated to Energy | $ 910,069 | $ 935,063 | $ 965,605 | $ 1,050,705 | $ 1,145,718 | $ 1,245,508 | $ 6,252,668 | $ 11,187,696 | | |
| 4 | Recoverable Costs Allocated to Demand | $ 376,253 | $ 377,041 | $ 384,863 | $ 392,664 | $ 393,414 | $ 396,426 | $ 2,320,661 | $ 4,518,459 | | |
| 5 | Retail Energy Jurisdictional Factor | 98.56595% | 98.56595% | 98.56595% | 98.56595% | 98.56595% | 98.56595% | | | | |
| 6 | Retail Demand Jurisdictional Factor | 98.63390% | 98.63390% | 98.63390% | 98.63390% | 98.63390% | 98.63390% | | | | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | $ 897,019 | $ 921,654 | $ 951,758 | $ 1,035,637 | $ 1,129,288 | $ 1,227,646 | $ 6,163,002 | $ 11,027,258 | | |
| 8 | Jurisdictional Demand Recoverable Costs (C) | $ 371,113 | $ 371,890 | $ 379,605 | $ 387,300 | $ 388,039 | $ 391,011 | $ 2,288,958 | $ 4,456,733 | | |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $ 1,268,132 | $ 1,293,544 | $ 1,331,363 | $ 1,422,937 | $ 1,517,327 | $ 1,618,657 | $ 8,451,960 | $ 15,483,991 | | |

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 12,121,440 | 12,233,532 | 12,345,623 | 12,457,715 | 12,569,807 | 12,681,899 | 12,793,991 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $5,490,028 | $5,377,936 | $5,265,845 | $5,153,753 | $5,041,661 | $4,929,569 | $4,817,477 | n/a |
| 6. | Average Net Investment | | 5,433,982 | 5,321,890 | 5,209,799 | 5,097,707 | 4,985,615 | 4,873,523 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 45,560 | 44,620 | 43,680 | 42,740 | 41,800 | 40,861 | 259,261 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 7,653 | 7,495 | 7,337 | 7,179 | 7,021 | 6,664 | 43,549 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 112,092 | 112,092 | 112,092 | 112,092 | 112,092 | 112,092 | 672,551 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $165,304 | $164,207 | $163,109 | $162,011 | $160,914 | $159,816 | $975,361 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burner Technology (Project No. 2)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-in-Service/Depreciation Base (B) | $17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | 17,611,468 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 12,793,991 | 12,906,083 | 13,018,174 | 13,130,266 | 13,242,358 | 13,354,450 | 13,466,542 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $4,817,477 | $4,705,385 | $4,593,294 | $4,481,202 | $4,369,110 | $4,257,018 | $4,144,926 | n/a |
| 6. | Average Net Investment | | 4,761,431 | 4,649,340 | 4,537,248 | 4,425,156 | 4,313,064 | 4,200,972 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 39,921 | 38,981 | 38,041 | 37,101 | 36,182 | 35,222 | 484,689 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 6,706 | 6,548 | 6,390 | 6,232 | 6,074 | 5,916 | 81,415 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 112,092 | 112,092 | 112,092 | 112,092 | 112,092 | 112,092 | 1,345,102 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $158,718 | $157,621 | $156,523 | $155,425 | $154,328 | $153,230 | $1,911,206 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $22,000 | $22,000 | $55,000 | $0 | $22,000 | $44,000 | $165,000 |
| | c. Retirements | | | | | | | | $0 |
| | d. Other (A) | | | | | | | | $0 |
| 2. | Plant-In-Service/Depreciation Base (B) | $12,632,481 | 12,654,481 | 12,676,481 | 12,731,481 | 12,731,481 | 12,753,481 | 12,797,481 | 0 |
| 3. | Less: Accumulated Depreciation (C) | 5,787,127 | 5,851,082 | 5,915,185 | 5,979,504 | 6,043,964 | 6,108,468 | 6,173,132 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $6,845,354 | $6,803,399 | $6,761,296 | $6,751,976 | $6,687,517 | $6,645,013 | $6,624,349 | n/a |
| 6. | Average Net Investment | | 6,824,376 | 6,782,348 | 6,756,636 | 6,719,747 | 6,666,265 | 6,634,681 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 57,217 | 56,865 | 56,649 | 56,340 | 55,891 | 55,627 | 338,588 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 9,611 | 9,552 | 9,516 | 9,464 | 9,388 | 9,344 | 56,874 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 63,955 | 64,103 | 64,320 | 64,459 | 64,504 | 64,664 | 386,005 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (2,286) | (2,286) | (2,286) | (2,286) | (2,286) | (2,286) | (13,716) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $128,497 | $128,233 | $128,198 | $127,977 | $127,498 | $127,349 | $767,752 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) Monthly depreciation offset for base rate retirements.

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Continuous Emissions Monitoring (Project No. 3b)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $11,000 | $0 | $88,000 | $44,000 | $0 | $308,000 |
| | c. Retirements | | | | | | | | $0 |
| | d. Other (A) | | | | | | | | $0 |
| 2. | Plant-In-Service/Depreciation Base (B) | $12,797,481 | 12,797,481 | 12,808,481 | 12,808,481 | 12,896,481 | 12,940,481 | 12,940,481 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 6,173,132 | 6,237,913 | 6,302,731 | 6,367,589 | 6,432,661 | 6,498,070 | 6,563,598 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $6,624,349 | $6,559,568 | $6,505,750 | $6,440,892 | $6,463,820 | $6,442,411 | $6,376,883 | n/a |
| 6. | Average Net Investment | | 6,591,959 | 6,532,659 | 6,473,321 | 6,452,356 | 6,453,115 | 6,409,647 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 55,268 | 54,771 | 54,274 | 54,098 | 54,104 | 53,740 | 664,843 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 9,284 | 9,200 | 9,117 | 9,087 | 9,088 | 9,027 | 111,677 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 64,780 | 64,819 | 64,857 | 65,073 | 65,408 | 65,528 | 776,471 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (2,754) | (2,754) | (2,754) | (2,754) | (2,754) | (2,754) | (30,240) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $126,578 | $126,036 | $125,494 | $125,504 | $125,847 | $125,541 | $1,522,752 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) Monthly depreciation offset for base rate retirements.

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $58,866 | 58,866 | 58,866 | 58,866 | 58,866 | 58,866 | 58,866 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 29,990 | 30,234 | 30,478 | 30,723 | 30,967 | 31,211 | 31,456 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $28,876 | $28,632 | $28,388 | $28,143 | $27,899 | $27,655 | $27,410 | n/a |
| 6. | Average Net Investment | | 28,754 | 28,510 | 28,265 | 28,021 | 27,777 | 27,532 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 241 | 239 | 237 | 235 | 233 | 231 | 1,416 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 40 | 40 | 40 | 39 | 39 | 39 | 238 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 244 | 244 | 244 | 244 | 244 | 244 | 1,466 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 6) | | $526 | $524 | $521 | $519 | $516 | $514 | $3,120 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Closure Equivalency (Project No. 4b)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $58,866 | 58,866 | 58,866 | 58,866 | 58,866 | 58,866 | 58,866 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 31,456 | 31,700 | 31,944 | 32,189 | 32,433 | 32,677 | 32,922 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $27,410 | $27,166 | $26,922 | $26,677 | $26,433 | $26,189 | $25,944 | n/a |
| 6. | Average Net Investment | | 27,288 | 27,044 | 26,799 | 26,555 | 26,311 | 26,066 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 229 | 227 | 225 | 223 | 221 | 219 | 2,758 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 38 | 38 | 38 | 37 | 37 | 37 | 463 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 244 | 244 | 244 | 244 | 244 | 244 | 2,932 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $512 | $509 | $507 | $504 | $502 | $500 | $6,154 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $14,053,123 | 14,053,123 | 14,053,123 | 14,053,123 | 14,053,123 | 14,053,123 | 14,053,123 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 1,750,075 | 1,789,827 | 1,829,579 | 1,869,332 | 1,909,084 | 1,948,836 | 1,988,589 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $12,303,048 | $12,263,296 | $12,223,544 | $12,183,791 | $12,144,039 | $12,104,287 | $12,064,534 | n/a |
| 6. | Average Net Investment | | 12,283,172 | 12,243,420 | 12,203,667 | 12,163,915 | 12,124,163 | 12,084,410 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 102,985 | 102,651 | 102,318 | 101,985 | 101,652 | 101,318 | 612,909 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 17,299 | 17,243 | 17,187 | 17,131 | 17,075 | 17,019 | 102,953 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 39,752 | 39,752 | 39,752 | 39,752 | 39,752 | 39,752 | 238,514 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (641) | (641) | (641) | (641) | (641) | (641) | (3,843) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $159,395 | $159,006 | $158,617 | $158,227 | $157,838 | $157,449 | $950,532 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) Monthly depreciation offset for base rate retirements.

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Maintenance of Above Ground Storage Tanks (Project No. 5b)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $14,053,123 | 14,053,123 | 14,053,123 | 14,053,123 | 14,053,123 | 14,053,123 | 14,053,123 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 1,988,589 | 2,028,341 | 2,068,093 | 2,107,846 | 2,147,598 | 2,187,350 | 2,227,103 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $12,064,534 | $12,024,782 | $11,985,030 | $11,945,277 | $11,905,525 | $11,865,773 | $11,826,020 | n/a |
| 6. | Average Net Investment | | 12,044,658 | 12,004,906 | 11,965,153 | 11,925,401 | 11,885,649 | 11,845,896 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 100,985 | 100,652 | 100,318 | 99,985 | 99,652 | 99,318 | 1,213,819 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 16,963 | 16,907 | 16,851 | 16,795 | 16,739 | 16,683 | 203,891 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 39,752 | 39,752 | 39,752 | 39,752 | 39,752 | 39,752 | 477,028 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (641) | (641) | (641) | (641) | (641) | (641) | (7,687) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $157,060 | $156,670 | $156,281 | $155,892 | $155,502 | $155,113 | $1,887,050 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) Monthly depreciation offset for base rate retirements.

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $31,030 | 31,030 | 31,030 | 31,030 | 31,030 | 31,030 | 31,030 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 17,579 | 17,731 | 17,884 | 18,036 | 18,189 | 18,342 | 18,494 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $13,451 | $13,299 | $13,146 | $12,994 | $12,841 | $12,688 | $12,536 | n/a |
| 6. | Average Net Investment | | 13,375 | 13,222 | 13,070 | 12,917 | 12,765 | 12,612 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 112 | 111 | 110 | 108 | 107 | 106 | 654 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 19 | 19 | 18 | 18 | 18 | 18 | 110 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 153 | 153 | 153 | 153 | 153 | 153 | 915 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $284 | $282 | $281 | $279 | $278 | $276 | $1,680 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Turbine Oil Underground Piping (Project No. 7)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $31,030 | 31,030 | 31,030 | 31,030 | 31,030 | 31,030 | 31,030 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 18,494 | 18,847 | 18,799 | 18,952 | 19,104 | 19,257 | 19,409 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $12,536 | $12,383 | $12,231 | $12,078 | $11,926 | $11,773 | $11,621 | n/a |
| 6. | Average Net Investment | | 12,460 | 12,307 | 12,155 | 12,002 | 11,849 | 11,697 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 104 | 103 | 102 | 101 | 99 | 98 | 1,261 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 18 | 17 | 17 | 17 | 17 | 16 | 212 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 153 | 153 | 153 | 153 | 153 | 153 | 1,831 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $275 | $273 | $272 | $270 | $269 | $267 | $3,306 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $100,000 | $100,000 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $688,075 | 688,075 | 688,075 | 688,075 | 688,075 | 688,075 | 788,075 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 442,954 | 450,896 | 458,837 | 466,779 | 474,720 | 482,662 | 491,199 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $245,121 | $237,179 | $229,238 | $221,296 | $213,355 | $205,413 | $296,876 | n/a |
| 6. | Average Net Investment | | 241,150 | 233,208 | 225,267 | 217,325 | 209,384 | 251,145 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 2,022 | 1,955 | 1,889 | 1,822 | 1,756 | 2,106 | 11,549 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 340 | 328 | 317 | 306 | 295 | 354 | 1,940 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 7,942 | 7,942 | 7,942 | 7,942 | 7,942 | 8,537 | 48,244 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $10,303 | $10,225 | $10,147 | $10,070 | $9,992 | $10,996 | $61,733 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Oil Spill Cleanup/Response Equipment (Project No. 8b)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | | $0 | $0 | $67,000 | $167,000 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $788,075 | 788,075 | 788,075 | 788,075 | 788,075 | 788,075 | 855,075 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 491,199 | 500,331 | 509,463 | 518,595 | 527,727 | 536,859 | 546,390 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $296,876 | $287,744 | $278,612 | $269,480 | $260,348 | $251,216 | $308,685 | n/a |
| 6. | Average Net Investment | | 292,310 | 283,178 | 274,046 | 264,914 | 255,782 | 279,951 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 2,451 | 2,374 | 2,298 | 2,221 | 2,145 | 2,347 | 25,385 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 412 | 399 | 386 | 373 | 360 | 394 | 4,264 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 9,132 | 9,132 | 9,132 | 9,132 | 9,132 | 9,531 | 103,435 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $11,994 | $11,905 | $11,816 | $11,726 | $11,637 | $12,272 | $133,083 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $117,794 | 117,794 | 117,794 | 117,794 | 117,794 | 117,794 | 117,794 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 38,619 | 38,933 | 39,248 | 39,562 | 39,876 | 40,190 | 40,504 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $79,175 | $78,861 | $78,546 | $78,232 | $77,918 | $77,604 | $77,290 | n/a |
| 6. | Average Net Investment | | 79,018 | 78,704 | 78,389 | 78,075 | 77,761 | 77,447 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 663 | 660 | 657 | 655 | 652 | 649 | 3,935 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 111 | 111 | 110 | 110 | 110 | 109 | 661 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 314 | 314 | 314 | 314 | 314 | 314 | 1,885 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $1,088 | $1,085 | $1,082 | $1,079 | $1,076 | $1,073 | $6,483 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Relocate Storm Water Runoff (Project No. 10)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $117,794 | 117,794 | 117,794 | 117,794 | 117,794 | 117,794 | 117,794 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 40,504 | 40,818 | 41,132 | 41,446 | 41,760 | 42,075 | 42,389 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $77,290 | $76,976 | $76,662 | $76,348 | $76,034 | $75,719 | $75,405 | n/a |
| 6. | Average Net Investment | | 77,133 | 76,819 | 76,505 | 76,191 | 75,877 | 75,562 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 647 | 644 | 641 | 639 | 636 | 634 | 7,776 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 109 | 108 | 108 | 107 | 107 | 106 | 1,306 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 314 | 314 | 314 | 314 | 314 | 314 | 3,769 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $1,069 | $1,066 | $1,063 | $1,060 | $1,057 | $1,054 | $12,852 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $864,260 | 864,260 | 864,260 | 864,260 | 864,260 | 864,260 | 864,260 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 351,031 | 354,060 | 357,088 | 360,117 | 363,146 | 366,175 | 369,204 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $513,229 | $510,200 | $507,172 | $504,143 | $501,114 | $498,085 | $495,056 | n/a |
| 6. | Average Net Investment | | 511,715 | 508,686 | 505,657 | 502,628 | 499,599 | 496,570 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 4,290 | 4,265 | 4,240 | 4,214 | 4,189 | 4,163 | 25,361 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 721 | 716 | 712 | 708 | 704 | 699 | 4,260 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 3,029 | 3,029 | 3,029 | 3,029 | 3,029 | 3,029 | 18,173 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $8,040 | $8,010 | $7,981 | $7,951 | $7,921 | $7,892 | $47,795 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Scherer Discharge Pipeline (Project No. 12)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $864,260 | 864,260 | 864,260 | 864,260 | 864,260 | 864,260 | 864,260 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 389,204 | 372,233 | 375,262 | 378,291 | 381,320 | 384,348 | 387,377 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $495,056 | $492,027 | $488,998 | $485,969 | $482,940 | $479,912 | $476,883 | n/a |
| 6. | Average Net Investment | | 493,542 | 490,513 | 487,484 | 484,455 | 481,426 | 478,397 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 4,138 | 4,113 | 4,087 | 4,062 | 4,036 | 4,011 | 49,808 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 695 | 691 | 687 | 682 | 678 | 674 | 8,366 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 3,029 | 3,029 | 3,029 | 3,029 | 3,029 | 3,029 | 36,347 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $7,862 | $7,832 | $7,803 | $7,773 | $7,743 | $7,714 | $94,522 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | n/a |
| 6. | Average Net Investment | | 0 | 0 | 0 | 0 | 0 | 0 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 6) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Non-Containerized Liquid Wastes (Project No. 17)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | n/a |
| 6. | Average Net Investment | | 0 | 0 | 0 | 0 | 0 | 0 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $1,938,995 | 1,938,995 | 1,938,995 | 1,938,995 | 1,938,995 | 1,938,995 | 1,938,995 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 391,581 | 399,843 | 408,104 | 416,366 | 424,628 | 432,889 | 441,151 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $1,547,414 | $1,539,152 | $1,530,891 | $1,522,629 | $1,514,368 | $1,506,106 | $1,497,844 | n/a |
| 6. | Average Net Investment | | 1,543,283 | 1,535,021 | 1,526,760 | 1,518,498 | 1,510,237 | 1,501,975 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 12,939 | 12,870 | 12,801 | 12,731 | 12,662 | 12,593 | 76,596 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 2,173 | 2,162 | 2,150 | 2,139 | 2,127 | 2,115 | 12,866 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 8,262 | 8,262 | 8,262 | 8,262 | 8,262 | 8,262 | 49,569 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $23,374 | $23,293 | $23,212 | $23,132 | $23,051 | $22,970 | $139,032 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Wasterwater/Stormwater Reuse (Project No. 20)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $250,000 | $250,000 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $1,938,995 | 1,938,995 | 1,938,995 | 1,938,995 | 1,938,995 | 1,938,995 | 2,188,995 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $441,151 | 449,412 | 457,674 | 465,935 | 474,197 | 482,458 | 491,230 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $1,497,844 | $1,489,583 | $1,481,321 | $1,473,060 | $1,464,798 | $1,456,537 | $1,697,765 | n/a |
| 6. | Average Net Investment | | 1,493,714 | 1,485,452 | 1,477,191 | 1,468,929 | 1,460,667 | 1,577,151 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | Equity Component grossed up for taxes (D) | | 12,524 | 12,454 | 12,385 | 12,316 | 12,247 | 13,223 | 151,745 |
| | Debt Component (Line 6 x 1.69% x 1/12) | | 2,104 | 2,092 | 2,080 | 2,069 | 2,057 | 2,221 | 25,489 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 8,262 | 8,262 | 8,262 | 8,262 | 8,262 | 8,772 | 99,649 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $22,889 | $22,808 | $22,727 | $22,646 | $22,565 | $24,216 | $276,883 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $828,789 | 828,789 | 828,789 | 828,789 | 828,789 | 828,769 | 828,789 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 56,264 | 58,474 | 60,684 | 62,895 | 65,105 | 67,315 | 69,525 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $772,525 | $770,315 | $768,105 | $765,895 | $763,684 | $761,474 | $759,264 | n/a |
| 6. | Average Net Investment | | 771,420 | 769,210 | 767,000 | 764,789 | 762,579 | 760,369 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 6,468 | 6,449 | 6,431 | 6,412 | 6,394 | 6,375 | 38,529 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 1,086 | 1,083 | 1,080 | 1,077 | 1,074 | 1,071 | 6,472 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 2,210 | 2,210 | 2,210 | 2,210 | 2,210 | 2,210 | 13,261 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (1,454) | (1,454) | (1,454) | (1,454) | (1,454) | (1,454) | (8,724) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $8,310 | $8,289 | $8,267 | $8,245 | $8,224 | $8,202 | $49,537 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) Depreciation offset for base rate items.

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Turtle Nets (Project No. 21)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $828,789 | 828,789 | 828,789 | 828,789 | 828,789 | 828,789 | 828,789 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $69,525 | 71,735 | 73,945 | 76,155 | 78,365 | 80,575 | 82,785 | n/a |
| 4. | CWIP - Non Interest Bearing | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $759,264 | $757,054 | $754,844 | $752,634 | $750,424 | $748,214 | $746,004 | n/a |
| 6. | Average Net Investment | | 758,159 | 755,949 | 753,739 | 751,529 | 749,319 | 747,109 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 6,357 | 6,338 | 6,320 | 6,301 | 6,282 | 6,264 | 76,390 |
| | b. Debt Component (Line 6 x 1.89% x 1/12) | | 1,068 | 1,065 | 1,062 | 1,058 | 1,055 | 1,052 | 12,832 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 2,210 | 2,210 | 2,210 | 2,210 | 2,210 | 2,210 | 26,521 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | (1,454) | (1,454) | (1,454) | (1,454) | (1,454) | (1,454) | (17,448) |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $8,180 | $8,159 | $8,137 | $8,115 | $8,094 | $8,072 | $98,294 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) Depreciation offset for base rate items.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $250,000 | 250,000 | 250,000 | 250,000 | 250,000 | 250,000 | 250,000 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 552 | 1,656 | 2,760 | 3,865 | 4,969 | 6,073 | 7,177 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $249,448 | $248,344 | $247,240 | $246,135 | $245,031 | $243,927 | $242,823 | n/a |
| 6. | Average Net Investment | | 248,896 | 247,792 | 246,687 | 245,583 | 244,479 | 243,375 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 2,087 | 2,078 | 2,068 | 2,059 | 2,050 | 2,041 | 12,382 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 351 | 349 | 347 | 346 | 344 | 343 | 2,080 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 1,104 | 1,104 | 1,104 | 1,104 | 1,104 | 1,104 | 6,625 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $3,541 | $3,531 | $3,520 | $3,509 | $3,498 | $3,487 | $21,086 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $0 | $0 | $1,192,844 | $0 | $0 | $0 | $1,192,844 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $250,000 | 250,000 | 250,000 | 1,442,844 | 1,442,844 | 1,442,844 | 1,442,844 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $7,177 | 8,281 | 9,385 | 12,279 | 16,962 | 21,644 | 26,327 | n/a |
| 4. | CWIP - Non Interest Bearing | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $242,823 | $241,719 | $240,615 | $1,430,565 | $1,425,882 | $1,421,200 | $1,416,517 | n/a |
| 6. | Average Net Investment | | 242,271 | 241,167 | 835,590 | 1,428,224 | 1,423,541 | 1,418,858 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 2,031 | 2,022 | 7,006 | 11,975 | 11,935 | 11,896 | 59,247 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 341 | 340 | 1,177 | 2,011 | 2,005 | 1,998 | 9,952 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 1,104 | 1,104 | 2,893 | 4,683 | 4,683 | 4,683 | 25,775 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $3,477 | $3,466 | $11,076 | $18,669 | $18,623 | $18,577 | $94,974 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $167,600 | $167,400 | $167,400 | $167,400 | $167,400 | $667,400 | $1,504,600 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $13,997,060 | 14,164,660 | 14,332,060 | 14,499,460 | 14,666,860 | 14,834,260 | 15,501,660 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 261,218 | 305,133 | 349,354 | 393,883 | 438,719 | 483,861 | 529,977 | n/a |
| 4. | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $13,735,841 | $13,859,527 | $13,982,705 | $14,105,576 | $14,228,141 | $14,350,399 | $14,971,683 | n/a |
| 6. | Average Net Investment | | 13,797,684 | 13,921,116 | 14,044,141 | 14,166,859 | 14,289,270 | 14,661,041 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 115,683 | 116,718 | 117,749 | 118,778 | 119,804 | 122,921 | 711,653 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 19,432 | 19,606 | 19,779 | 19,952 | 20,124 | 20,648 | 119,539 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 43,915 | 44,222 | 44,529 | 44,835 | 45,142 | 46,116 | 268,759 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $179,029 | $180,545 | $182,056 | $183,565 | $185,071 | $189,685 | $1,099,951 |

**Notes:**

(A) Reserve Transfer in February.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.16% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Spill Prevention (Project No. 23)
(In Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | | | | | | | |
| | b. Clearings to Plant | | $167,400 | $167,400 | $167,400 | $167,400 | $167,400 | $167,400 | $2,509,000 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $15,501,660 | 15,669,060 | 15,836,460 | 16,003,860 | 16,171,260 | 16,338,660 | 16,506,060 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $529,977 | 577,066 | 624,463 | 672,166 | 720,176 | 768,493 | 817,117 | n/a |
| 4. | CWIP - Non Interest Bearing | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5. | Net Investment (Lines 2 - 3 + 4) | $14,971,683 | $15,091,994 | $15,211,997 | $15,331,694 | $15,451,084 | $15,570,167 | $15,688,943 | n/a |
| 6. | Average Net Investment | | 15,031,838 | 15,151,995 | 15,271,846 | 15,391,389 | 15,510,625 | 15,629,555 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 126,030 | 127,037 | 128,042 | 129,045 | 130,044 | 131,041 | 1,482,893 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 21,170 | 21,339 | 21,508 | 21,676 | 21,844 | 22,012 | 249,088 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 47,090 | 47,396 | 47,703 | 48,010 | 48,317 | 48,624 | 555,899 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $194,289 | $195,773 | $197,253 | $198,731 | $200,206 | $201,677 | $2,287,880 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | $288,565 | $1,593,000 | $2,000 | $1,568,000 | $2,000 | $2,000 | $3,455,565 |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | c. Retirements | | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n/a |
| 4. | CWIP - Non Interest Bearing | 11,559,183 | 11,847,748 | 13,440,748 | 13,442,748 | 15,010,748 | 15,012,748 | 15,014,748 | n/a |
| 5. | Net Investment (Lines 2 - 3 + 4) | $11,559,183 | $11,847,748 | $13,440,748 | $13,442,748 | $15,010,748 | $15,012,748 | $15,014,748 | n/a |
| 6. | Average Net Investment | | 11,703,465 | 12,644,248 | 13,441,748 | 14,226,748 | 15,011,748 | 15,013,748 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 98,124 | 106,012 | 112,698 | 119,280 | 125,862 | 125,878 | 687,855 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 16,482 | 17,807 | 18,930 | 20,036 | 21,142 | 21,144 | 115,542 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $114,607 | $123,819 | $131,629 | $139,316 | $147,003 | $147,023 | $803,397 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | $4,000 | $904,000 | $690,500 | $1,432,000 | $1,080,882 | $5,496,432 | $13,063,379 |
| | b. Clearings to Plant | | $0 | $0 | $0 | $0 | $0 | $15,454,835 | $15,454,835 |
| | c. Retirements | | $0 | $0 | $0 | $0 | $0 | $25,758 | $25,758 |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 0 | 0 | 15,454,835 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $0 | 0 | 0 | 0 | 0 | 0 | 25,758 | n/a |
| 4. | CWIP - Non Interest Bearing | $15,014,748 | 15,018,748 | 15,922,748 | 16,613,248 | 18,045,248 | 19,126,130 | 9,167,727 | n/a |
| 5. | Net Investment (Lines 2 - 3 + 4) | $15,014,748 | $15,018,748 | $15,922,748 | $16,613,248 | $18,045,248 | $19,126,130 | $24,622,562 | n/a |
| 6. | Average Net Investment | | 15,016,748 | 15,470,748 | 16,267,998 | 17,329,248 | 18,585,689 | 21,874,348 | n/a |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 125,904 | 129,710 | 136,394 | 145,292 | 155,826 | 183,399 | 1,564,380 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 21,149 | 21,788 | 22,911 | 24,405 | 26,175 | 30,806 | 262,776 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 25,758 | $25,758 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $147,052 | $151,498 | $159,305 | $169,697 | $182,001 | $239,964 | $1,852,914 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | Six Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | $2,383,073 | $2,010,000 | $832,600 | $526,000 | $1,322,571 | $1,526,000 | $8,600,244 |
| | b. Clearings to Plant | | $0 | $0 | $17,688,316 | $0 | $0 | $0 | $17,688,316 |
| | c. Retirements | | | | | | | | $0 |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $0 | 0 | 0 | 17,688,316 | 17,688,316 | 17,688,316 | 17,688,316 | n/a |
| 3. | Less: Accumulated Depreciation (C) | 0 | 0 | 0 | 47,906 | 143,718 | 239,529 | 335,341 | n/a |
| 4. | CWIP - Non Interest Bearing | 28,709,826 | 31,092,899 | 33,102,899 | 16,247,183 | 16,773,183 | 18,095,754 | 19,621,754 | n/a |
| 5. | Net Investment (Lines 2 - 3 + 4) | $28,709,826 | $31,092,899 | $33,102,899 | $33,887,593 | $34,317,782 | $35,544,541 | $36,974,729 | n/a |
| 6. | Average Net Investment | | 29,901,363 | 32,097,899 | 33,495,246 | 34,102,687 | 34,931,161 | 36,259,635 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 250,699 | 269,115 | 280,831 | 285,924 | 292,870 | 304,008 | 1,683,448 |
| | b. Debt Component (Line 6 x 1.69% x 1/12) | | 42,111 | 45,205 | 47,172 | 48,028 | 49,195 | 51,066 | 282,776 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | | | 47,906 | 95,812 | 95,812 | 95,812 | 335,341 |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $292,810 | $314,320 | $375,909 | $429,764 | $437,877 | $450,886 | $2,301,566 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | Twelve Month Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | |
| | a. Expenditures/Additions | | $1,948,159 | $2,724,286 | $2,275,143 | $3,936,029 | $4,052,462 | $4,925,142 | $28,461,465 |
| | b. Clearings to Plant | | $0 | $0 | $0 | $17,986,457 | $0 | $250,000 | $35,924,773 |
| | c. Retirements | | | | | | | | |
| | d. Other (A) | | | | | | | | |
| 2. | Plant-In-Service/Depreciation Base (B) | $17,688,316 | 17,688,316 | 17,688,316 | 17,688,316 | 35,674,773 | 35,674,773 | 35,924,773 | n/a |
| 3. | Less: Accumulated Depreciation (C) | $335,341 | 431,153 | 526,964 | 622,776 | 764,303 | 951,546 | 1,139,466 | n/a |
| 4. | CWIP - Non Interest Bearing | $19,621,754 | 21,569,913 | 24,294,199 | 26,569,342 | 12,518,914 | 16,571,376 | 21,246,518 | n/a |
| 5. | Net Investment (Lines 2 - 3 + 4) | $36,974,729 | $38,827,076 | $41,455,551 | $43,634,882 | $47,429,384 | $51,294,603 | $56,031,825 | n/a |
| 6. | Average Net Investment | | 37,900,903 | 40,141,314 | 42,545,216 | 45,532,133 | 49,361,993 | 53,663,214 | |
| 7. | Return on Average Net Investment | | | | | | | | |
| | a. Equity Component grossed up for taxes (D) | | 317,769 | 336,553 | 356,708 | 381,751 | 413,861 | 449,924 | $3,940,014 |
| | b. Debt Component (Line 8 x 1.69% x 1/12) | | 53,377 | 56,532 | 59,918 | 64,124 | 69,518 | 75,576 | $661,822 |
| 8. | Investment Expenses | | | | | | | | |
| | a. Depreciation (E) | | 95,812 | 95,812 | 95,812 | 141,527 | 187,243 | 187,920 | |
| | b. Amortization (F) | | | | | | | | |
| | c. Dismantlement | | | | | | | | |
| | d. Property Expenses | | | | | | | | |
| | e. Other (G) | | | | | | | | |
| 9. | Total System Recoverable Expenses (Lines 7 & 8) | | $466,958 | $488,897 | $512,438 | $587,403 | $670,622 | $713,419 | $5,741,303 |

**Notes:**

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period January through June 2005**

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(in Dollars)

| Line | | Beginning of Period Amount | January Projected | February Projected | March Projected | April Projected | May Projected | June Projected | End of Period Amount | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | |
| | a 158.100 Allowance Inventory | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| | b 158.200 Allowances Withheld | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| | c 182.300 Other Regulatory Assets-Losses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| | d 254.900 Other Regulatory Liabilities-Gains | (1,516,143) | (1,497,590) | (1,479,037) | (1,460,483) | (1,441,930) | (2,130,534) | (2,111,981) | | |
| 2 | Total Working Capital | ($1,516,143) | ($1,497,590) | ($1,479,037) | ($1,460,483) | ($1,441,930) | ($2,130,534) | ($2,111,981) | | |
| 3 | Average Net Working Capital Balance | | (1,506,867) | (1,488,313) | (1,469,760) | (1,451,207) | (1,786,232) | (2,121,257) | | |
| 4 | Return on Average Net Working Capital Balance | | | | | | | | | |
| | a Equity Component grossed up for taxes (A) | | (12,634) | (12,478) | (12,323) | (12,167) | (14,976) | (17,785) | (82,363) | |
| | b Debt Component (Line 6 x 1.69% x 1/12) | | (2,122) | (2,096) | (2,070) | (2,044) | (2,516) | (2,987) | (13,835) | |
| 5 | Total Return Component | | ($14,756) | ($14,574) | ($14,393) | ($14,211) | ($17,492) | ($20,773) | ($96,198) | (D) |
| 6 | Expense Dr (Cr) | | | | | | | | | |
| | a 411.800 Gains from Dispositions of Allowances | | (18,553) | (18,553) | (18,553) | (18,553) | (18,553) | (18,553) | (111,318) | |
| | b 411.900 Losses from Dispositions of Allowances | | 0 | 0 | 0 | 0 | 0 | 0 | - | |
| | c 509.000 Allowance Expense | | 0 | 0 | 0 | 0 | 0 | 0 | - | |
| 7 | Net Expense (Lines 6a+6b+6c) | | (18,553) | (18,553) | (18,553) | (18,553) | (18,553) | (18,553) | (111,318) | (E) |
| 8 | Total System Recoverable Expenses (Lines 5+7) | | (33,309) | (33,127) | (32,946) | (32,764) | (36,045) | (39,326) | | |
| | a Recoverable Costs Allocated to Energy | | (33,309) | (33,127) | (32,946) | (32,764) | (36,045) | (39,326) | | |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | | |
| 9 | Energy Jurisdictional Factor | | 98.53755% | 98.53755% | 98.53755% | 98.53755% | 98.53755% | 98.53755% | | |
| 10 | Demand Jurisdictional Factor | | 97.87297% | 97.87297% | 97.87297% | 97.87297% | 97.87297% | 97.87297% | | |
| 11 | Retail Energy-Related Recoverable Costs (B) | | (32,622) | (32,643) | (32,464) | (32,285) | (35,518) | (38,750) | (204,482) | |
| 12 | Retail Demand-Related Recoverable Costs (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 13 | Total Jurisdictional Recoverable Costs (Lines11+12) | | ($32,822) | ($32,643) | ($32,464) | ($32,285) | ($35,518) | ($38,750) | ($204,482) | |

**Notes:**

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding

**Florida Power & Light Company**
Environmental Cost Recovery Clause
**For the Projected Period July through December 2005**

Schedule of Amortization of and Negative Return on
Deferred Gain on Sales of Emission Allowances
(in Dollars)

| Line | | Beginning of Period Amount | July Projected | August Projected | September Projected | October Projected | November Projected | December Projected | End of Period Amount | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | |
| | a 158.100 Allowance Inventory | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| | b 158.200 Allowances Withheld | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| | c 182.300 Other Regulatory Assets-Losses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| | d 254.900 Other Regulatory Liabilities-Gains | (2,111,981) | (2,093,428) | (2,074,874) | (2,056,321) | (2,037,768) | (2,019,214) | (2,000,661) | | |
| 2 | Total Working Capital | ($2,111,981) | ($2,093,428) | ($2,074,874) | ($2,056,321) | ($2,037,768) | ($2,019,214) | ($2,000,661) | | |
| 3 | Average Net Working Capital Balance | | (2,102,704) | (2,084,151) | (2,065,598) | (2,047,044) | (2,028,491) | (2,009,938) | | |
| 4 | Return on Average Net Working Capital Balance | | | | | | | | | |
| | a Equity Component grossed up for taxes (A) | | (17,630) | (17,474) | (17,318) | (17,183) | (17,007) | (16,852) | (185,807) | |
| | b Debt Component (Line 6 x 1.69% x 1/12) | | (2,961) | (2,935) | (2,909) | (2,883) | (2,857) | (2,831) | (31,211) | |
| 5 | Total Return Component | | ($20,591) | ($20,409) | ($20,227) | ($20,046) | ($19,864) | ($19,682) | ($217,018) | (D) |
| 6 | Expense Dr (Cr) | | | | | | | | | |
| | a 411.800 Gains from Dispositions of Allowances | | (18,553) | (18,553) | (18,553) | (18,553) | (18,553) | (18,553) | (222,636) | |
| | b 411.900 Losses from Dispositions of Allowances | | 0 | 0 | 0 | 0 | 0 | 0 | - | |
| | c 509.000 Allowance Expense | | 0 | 0 | 0 | 0 | 0 | 0 | - | |
| 7 | Net Expense (Lines 6a+6b+6c) | | (18,553) | (18,553) | (18,553) | (18,553) | (18,553) | (18,553) | (222,636) | (E) |
| 8 | Total System Recoverable Expenses (Lines 5+7) | | ($39,144) | ($38,962) | ($38,780) | ($38,599) | ($38,417) | ($38,235) | | |
| | a Recoverable Costs Allocated to Energy | | (39,144) | (38,962) | (38,780) | (38,599) | (38,417) | (38,235) | | |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | | |
| 9 | Energy Jurisdictional Factor | | 98.53755% | 98.53755% | 98.53755% | 98.53755% | 98.53755% | 98.53755% | | |
| 10 | Demand Jurisdictional Factor | | 97.87297% | 97.87297% | 97.87297% | 97.87297% | 97.87297% | 97.87297% | | |
| 11 | Retail Energy-Related Recoverable Costs (B) | | (38,571) | (38,392) | (38,213) | (38,034) | (37,855) | (37,676) | (433,224) | |
| 12 | Retail Demand-Related Recoverable Costs (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 13 | Total Jurisdictional Recoverable Costs (Lines11+12) | | ($38,571) | ($38,392) | ($38,213) | ($38,034) | ($37,855) | ($37,676) | ($433,224) | |

**Notes:**

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

In accordance with FPSC Order No. PSC-94-0393-FOF-EI, FPL has recorded the gains on sales of emissions allowances as a regulatory liability.

Totals may not add due to rounding

| Project Number | Plant Name | Plant Account | Depreciation Rate / Amortization Period | Projected January Plant In Service (BOM) | Projected December Plant In Service (EOM) |
|---|---|---|---|---|---|
| **02 - Low NOX Burner Technology** | | | | | |
| | PtEverglades U1 | 312.0 | 6.10% | $2,700,574.97 | $2,700,574.97 |
| | PtEverglades U2 | 312.0 | 6.50% | $2,377,900.75 | $2,377,900.75 |
| | Riviera U3 | 312.0 | 8.90% | $3,846,591.65 | $3,846,591.65 |
| | Riviera U4 | 312.0 | 7.90% | $3,272,970.68 | $3,272,970.68 |
| | Turkey Pt U1 | 312.0 | 8.80% | $2,961,524.84 | $2,961,524.84 |
| | Turkey Pt U2 | 312.0 | 6.70% | $2,451,904.92 | $2,451,904.92 |
| | **Total For Project 02** | | | **$17,611,467.81** | **$17,611,467.81** |
| **03 - Continuous Emission Monitoring** | | | | | |
| | CapeCanaveral Comm | 311.0 | 4.90% | $59,227.10 | $59,227.10 |
| | CapeCanaveral Comm | 312.0 | 8.50% | $31,735.95 | $31,735.95 |
| | CapeCanaveral U1 | 312.0 | 8.80% | $494,606.87 | $505,606.87 |
| | CapeCanaveral U2 | 312.0 | 8.30% | $511,705.24 | $522,705.24 |
| | Cutler Comm | 311.0 | 5.20% | $64,883.87 | $64,883.87 |
| | Cutler Comm | 312.0 | 4.50% | $27,351.73 | $27,351.73 |
| | Cutler U5 | 312.0 | 5.00% | $312,722.43 | $323,722.43 |
| | Cutler U6 | 312.0 | 5.10% | $314,129.96 | $325,129.96 |
| | Manatee Comm | 312.0 | 4.60% | $31,859.00 | $31,859.00 |
| | Manatee U1 | 311.0 | 2.90% | $56,430.25 | $56,430.25 |
| | Manatee U1 | 312.0 | 4.00% | $472,570.03 | $483,570.03 |
| | Manatee U2 | 311.0 | 3.00% | $56,332.75 | $56,332.75 |
| | Manatee U2 | 312.0 | 4.20% | $508,734.36 | $519,734.36 |
| | Martin Comm | 312.0 | 4.60% | $31,631.74 | $31,631.74 |
| | Martin U1 | 311.0 | 3.30% | $36,810.86 | $36,810.86 |
| | Martin U1 | 312.0 | 4.80% | $521,075.17 | $532,075.17 |
| | Martin U2 | 311.0 | 3.30% | $36,845.37 | $36,845.37 |
| | Martin U2 | 312.0 | 4.90% | $519,484.96 | $530,484.96 |
| | PtEverglades Comm | 311.0 | 5.80% | $127,911.34 | $127,911.34 |
| | PtEverglades Comm | 312.0 | 7.70% | $61,620.47 | $61,620.47 |
| | PtEverglades U1 | 312.0 | 6.10% | $453,661.22 | $464,661.22 |
| | PtEverglades U2 | 312.0 | 6.50% | $475,113.36 | $486,113.36 |
| | PtEverglades U3 | 312.0 | 7.80% | $503,968.62 | $514,968.62 |
| | PtEverglades U4 | 312.0 | 8.40% | $512,809.90 | $523,809.90 |
| | Riviera Comm | 311.0 | 5.20% | $60,973.18 | $60,973.18 |
| | Riviera Comm | 312.0 | 8.90% | $29,117.75 | $29,117.75 |
| | Riviera U3 | 312.0 | 8.90% | $449,392.38 | $460,392.38 |
| | Riviera U4 | 312.0 | 7.90% | $433,421.96 | $444,421.96 |
| | Sanford U3 | 311.0 | 2.40% | $54,282.08 | $54,282.08 |
| | Sanford U3 | 312.0 | 2.40% | $131,944.80 | $131,944.80 |
| | Sanford U3 (Retiring | 312.0 | 0.00% | $315,699.69 | $315,699.69 |
| | Scherer U4 | 312.0 | 4.50% | $515,653.32 | $515,653.32 |
| | SJRPP - Comm | 311.0 | 3.40% | $43,193.33 | $43,193.33 |
| | SJRPP - Comm | 312.0 | 3.70% | $66,188.18 | $66,188.18 |
| | SJRPP U1 | 312.0 | 4.10% | $107,594.02 | $107,594.02 |
| | SJRPP U2 | 312.0 | 4.20% | $107,562.94 | $107,562.94 |
| | Turkey Pt Comm Fsil | 311.0 | 4.30% | $59,056.19 | $59,056.19 |
| | Turkey Pt Comm Fsil | 312.0 | 6.90% | $29,110.85 | $29,110.85 |
| | Turkey Pt U1 | 312.0 | 8.80% | $546,534.15 | $557,534.15 |
| | Turkey Pt U2 | 312.0 | 6.70% | $505,638.44 | $516,638.44 |
| | FtLauderdale Comm | 341.0 | 5.30% | $58,859.79 | $58,859.79 |
| | FtLauderdale Comm | 345.0 | 4.20% | $34,502.21 | $34,502.21 |
| | FtLauderdale U4 | 343.0 | 6.50% | $461,080.14 | $483,080.14 |
| | FtLauderdale U5 | 343.0 | 6.60% | $471,313.47 | $493,313.47 |
| | FtMyers U2 CC | 343.0 | 5.50% | $101,353.39 | $101,353.39 |
| | Martin U3 | 343.0 | 5.70% | $431,927.00 | $453,927.00 |
| | Martin U4 | 343.0 | 5.50% | $421,026.31 | $443,026.31 |
| | Martin U8 | 343.0 | 5.50% | $25,657.00 | $25,657.00 |
| | Putnam Comm | 341.0 | 4.20% | $82,857.82 | $82,857.82 |
| | Putnam Comm | 343.0 | 5.60% | $3,138.97 | $3,138.97 |
| | Putnam U1 | 343.0 | 6.00% | $335,440.55 | $357,440.55 |
| | Putnam U2 | 343.0 | 6.30% | $368,844.07 | $390,844.07 |
| | Sanford Comm CC | 343.0 | 11.60% | $5,168.21 | $5,168.21 |
| | Sanford U4 | 343.0 | 5.50% | $41,859.48 | $41,859.48 |
| | Sanford U5 | 343.0 | 5.50% | $100,938.52 | $100,938.52 |
| | General Plant | 391.9 | 3Yr | $9,927.75 | $9,927.75 |
| | **Total For Project 03** | | | **$12,632,480.49** | **$12,940,480.49** |

| Project Number | Plant Name | Plant Account | Depreciation Rate / Amortization Period | Projected January Plant In Service (BOM) | Projected December Plant In Service (EOM) |
|---|---|---|---|---|---|
| **04 - Clean Closure Equivalency Demonstration** | | | | | |
| | CapeCanaveral Comm | 311.0 | 4.90% | $17,254.20 | $17,254.20 |
| | PtEverglades Comm | 311.0 | 5.80% | $19,812.30 | $19,812.30 |
| | Turkey Pt Comm Fsil | 311.0 | 4.30% | $21,799.28 | $21,799.28 |
| | Total For Project 04 | | | $58,865.78 | $58,865.78 |
| **05 - Maintenance of Above Ground Fuel Tanks** | | | | | |
| | CapeCanaveral Comm | 311.0 | 4.90% | $901,636.88 | $901,636.88 |
| | Manatee Comm | 311.0 | 3.50% | $3,111,263.35 | $3,111,263.35 |
| | Manatee Comm | 312.0 | 4.60% | $174,543.23 | $174,543.23 |
| | Manatee U1 | 312.0 | 4.00% | $104,845.35 | $104,845.35 |
| | Manatee U2 | 312.0 | 4.20% | $127,429.19 | $127,429.19 |
| | Martin Comm | 311.0 | 3.60% | $1,110,450.32 | $1,110,450.32 |
| | Martin U1 | 311.0 | 3.30% | $176,338.83 | $176,338.83 |
| | PtEverglades Comm | 311.0 | 5.80% | $1,132,078.22 | $1,132,078.22 |
| | Riviera Comm | 311.0 | 5.20% | $1,042,734.82 | $1,042,734.82 |
| | Sanford U3 | 311.0 | 2.40% | $796,754.11 | $796,754.11 |
| | SJRPP - Comm | 311.0 | 3.40% | $42,091.24 | $42,091.24 |
| | SJRPP - Comm | 312.0 | 3.70% | $2,292.39 | $2,292.39 |
| | Turkey Pt Comm Fsil | 311.0 | 4.30% | $87,560.23 | $87,560.23 |
| | Turkey Pt U2 | 311.0 | 5.20% | $42,158.96 | $42,158.96 |
| | FtLauderdale Comm | 342.0 | 4.30% | $898,110.65 | $898,110.65 |
| | FtLauderdale GTs | 342.0 | 0.70% | $584,290.23 | $584,290.23 |
| | FtMyers GTs | 342.0 | 1.20% | $68,893.65 | $68,893.65 |
| | PtEverglades GTs | 342.0 | 1.40% | $2,900,625.16 | $2,900,625.16 |
| | Putnam Comm | 342.0 | 4.00% | $749,025.94 | $749,025.94 |
| | Total For Project 05 | | | $14,053,122.75 | $14,053,122.75 |
| **07 - Relocate Turbine Lube Oil Piping** | | | | | |
| | StLucie U1 | 323.0 | 5.90% | $31,030.00 | $31,030.00 |
| | Total For Project 07 | | | $31,030.00 | $31,030.00 |
| **08 - Oil Spill Clean-up/Response Equipment** | | | | | |
| | CapeCanaveral Comm | 316.7 | 7Yr | $2,741.16 | $2,741.16 |
| | Martin Comm | 316.0 | 4.40% | $23,107.32 | $23,107.32 |
| | Martin Comm | 316.5 | 5Yr | $15,228.31 | $15,228.31 |
| | Martin Comm | 316.7 | 7Yr | $565,012.49 | $565,012.49 |
| | Sanford U3 | 316.7 | 7Yr | $6,776.50 | $6,776.50 |
| | Turkey Pt Comm Fsil | 316.7 | 7Yr | $7,050.46 | $7,050.46 |
| | Turkey Pt U1 (Asset 3933 | 316.7 | 7Yr | $1,159.18 | $1,159.18 |
| | FtMyers Common | 346.7 | 7Yr | $12,051.85 | $12,051.85 |
| | Various Plants Common | 346.7 | 7Yr | $54,948.00 | $221,948.00 |
| | Total For Project 08 | | | $688,075.27 | $855,075.27 |
| **10 - Reroute Storm Water Runoff** | | | | | |
| | StLucie Comm | 321.0 | 3.20% | $117,793.83 | $117,793.83 |
| | Total For Project 10 | | | $117,793.83 | $117,793.83 |
| **12 - Scherer Discharge Pipline** | | | | | |
| | Scherer Comm | 310.0 | 0.00% | $9,936.72 | $9,936.72 |
| | Scherer Comm | 311.0 | 3.60% | $524,872.97 | $524,872.97 |
| | Scherer Comm | 312.0 | 5.30% | $328,761.62 | $328,761.62 |
| | Scherer Comm | 314.0 | 3.90% | $689.11 | $689.11 |
| | Total For Project 12 | | | $864,260.42 | $864,260.42 |
| **20 - Wastewater/Stormwater Discharge Elimination** | | | | | |
| | CapeCanaveral Comm | 311.0 | 4.90% | $856,500.94 | $856,500.94 |
| | Martin U1 | 312.0 | 4.80% | $225,000.00 | $225,000.00 |
| | Martin U2 | 312.0 | 4.90% | $0.00 | $250,000.00 |
| | PtEverglades Comm | 311.0 | 5.80% | $296,707.34 | $296,707.34 |
| | Riviera Comm | 311.0 | 5.20% | $560,786.81 | $560,786.81 |
| | Total For Project 20 | | | $1,938,995.09 | $2,188,995.09 |
| **21 - St. Lucie Turtle Nets** | | | | | |
| | StLucie Comm | 321.0 | 3.20% | $828,789.34 | $828,789.34 |
| | Total For Project 21 | | | $828,789.34 | $828,789.34 |

| Project Number | Plant Name | Plant Account | Depreciation Rate / Amortization Period | Projected January Plant In Service (BOM) | Projected December Plant In Service (EOM) |
|---|---|---|---|---|---|
| **22 - Pipeline Integrity Management (PIM)** | | | | | |
| | Martin Comm | 311.0 | 3.60% | $0.00 | $1,192,844.00 |
| | FtLauderdale Comm | 341.0 | 5.30% | $250,000.00 | $250,000.00 |
| | **Total For Project 22** | | | $250,000.00 | $1,442,844.00 |
| **23 - Spill Prevention Clean-Up & Countermeasures** | | | | | |
| | CapeCanaveral Comm | 312.0 | 8.50% | $812,364.10 | $812,364.10 |
| | Cutler Comm | 312.0 | 4.50% | $88,115.33 | $88,115.33 |
| | Manatee Comm | 312.0 | 4.60% | $518,002.68 | $518,002.68 |
| | Martin Comm | 312.0 | 4.60% | $66,682.03 | $66,682.03 |
| | Riviera Common | 312.0 | 8.90% | $153,023.85 | $153,023.85 |
| | Riviera U3 | 312.0 | 8.90% | $757,398.09 | $757,398.09 |
| | Riviera U4 | 312.0 | 7.90% | $885,578.22 | $885,578.22 |
| | Sanford Common | 312.0 | 3.50% | $764,671.10 | $764,671.10 |
| | Turkey Pt Comm Fsil | 312.0 | 6.90% | $30,326.82 | $30,326.82 |
| | StLucie U1 | 324.0 | 3.20% | $0.00 | $500,000.46 |
| | FtLauderdale Comm | 342.0 | 4.30% | $1,252,502.81 | $1,252,502.81 |
| | FtLauderdale GTs | 342.0 | 0.70% | $553,266.61 | $553,266.61 |
| | FtMyers GTs | 342.0 | 1.20% | $855,065.85 | $855,065.85 |
| | PtEverglades GTs | 342.0 | 1.40% | $1,879,867.81 | $1,879,867.81 |
| | Putnam Comm | 342.0 | 4.00% | $1,816,787.37 | $1,816,787.37 |
| | Transmission | 352.0 | 2.20% | $891,327.74 | $1,393,577.74 |
| | Distribution | 361.0 | 2.20% | $2,672,078.39 | $4,178,828.39 |
| | **Total For Project 23** | | | $13,997,059.80 | $16,506,060.26 |
| **24 - Manatee Reburn** | | | | | |
| | Manatee U1 | 312.0 | 4.00% | $0.00 | $15,454,835.40 |
| | **Total For Project 24** | | | $0.00 | $15,454,835.40 |
| **25 - PPE ESP Technology** | | | | | |
| | PtEverglades U1 | 312.0 | 6.10% | $0.00 | $17,986,456.89 |
| | PtEverglades U2 | 312.0 | 6.50% | $0.00 | $17,938,316.18 |
| | **Total For Project 25** | | | $0.00 | $35,924,773.07 |
| | | | | $63,071,940.58 | $118,878,393.51 |

# FLORIDA POWER & LIGHT COMPANY
# PROJECT DESCRIPTION AND PROGRESS

**Project Title:** Air Operating Permit Fees – O&M
**Project No. 1**
**Project Description:**
The Clean Air Act Amendments of 1990, Public Law 101-549, and Florida Statutes 403.0872, require each major source of air pollution to pay an annual license fee. The amount of the fee is based on each source's previous year's emissions. It is calculated by multiplying the applicable annual operation license fee factor ($25 per ton for both Florida and Georgia) by the tons of each air pollutant emitted by the unit during the previous year and regulated in each unit's air operating permit, up to a total of 4,000 tons per pollutant. The major regulated pollutants at the present time are sulfur dioxide ($SO_2$), nitrogen oxides ($NO_x$) and particulate matter. The fee covers units in FPL's service area, as well as Unit 4 of Plant Scherer located in Juliette, Georgia, within the Georgia Power Company service area. Scherer Unit 4's annual air operating permit fee is approximately $ 96,000. FPL's share of ownership of that unit is 76.36%. The fees for FPL's units are paid to the Florida Department of Environmental Protection (FDEP) generally in February of each year, whereas FPL pays its share of the fees for Scherer Unit 4 to Georgia Power Company on a monthly basis.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
The monthly fees for 2003 emissions at Scherer have been paid and continue to be paid in 2004. 2003 air operating permit fees for the Florida facilities were calculated in January 2004 utilizing 2003 operating information. They were paid to the FDEP in March 2004.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $189,254 or 9.2% lower than previously projected. The process for estimating air permit fees has been refined in order to produce more accurate estimates.

**Project Progress Summary:**
The monthly fees for 2003 emissions at Scherer have been paid and continue to be paid in 2004. 2003 air operating permit fees for the Florida facilities were calculated in January 2004 utilizing 2003 operating information. They were paid to the FDEP in March 2004.

**Project Projections:**
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $1,908,804.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Continuous Emission Monitoring Systems - O & M
**Project No. 3a**
**Project Description:**
The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping and reporting of $SO_2$, $NO_x$ and carbon dioxide ($CO_2$) emissions, as well as volumetric flow and opacity data from affected air pollution sources. FPL has 33 units which are affected and which have installed CEMS to comply with these requirements.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMS and specific requirements for the monitoring of pollutants, opacity and volumetric flow. Periodically, these systems extract and analyze gaseous samples for each power plant stack and have automated data acquisition and reporting capability. Operation and maintenance of these systems in accordance with the provisions of 40 CFR Part 75 will be an ongoing activity following their installation.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
Relative Accuracy Tests and Linearity Tests continue to be performed as scheduled. Maintenance has been performed on the analyzers. Calibration gases and CEMS parts have been purchased. Analysis of the fuel oil for sulfur content continues to be performed.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $79,952 or 12.6% higher than previously projected primarily due to higher than originally projected payments to the software vendor for technical support.

**Project Progress Summary:**
This is an ongoing project. Each reporting period will include the cost of quality assurance activities, training, spare parts, calibration gas, and software support.

**Project Projections:**
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $711,876.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Clean Closure Equivalency - O&M
**Project No. 4a**
**Project Description:**
In compliance with 40 CFR 270.1(c)(5) and (6), FPL developed CCED's for nine FPL power plants to demonstrate to the U.S. EPA that no hazardous waste or hazardous constituents remain in the soil or water beneath the basins which had been used in the past to treat corrosive hazardous waste. The basins, which are still operational as part of the wastewater treatment systems at these plants, are no longer used to treat hazardous waste.

To demonstrate clean closure, soil sampling and ground water monitoring plans, implementation schedules, and related reports must be submitted to the EPA. Capital costs are for the installation of monitoring wells (typically four per site) necessary to collect ground water samples for analysis.

**Project Accomplishments:**
All activities are complete.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
None

**Project Progress Summary:**
Complete

**Project Projections:**
None

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Maintenance of Stationary Above Ground Fuel Storage Tanks - O&M
**Project No. 5a**
**Project Description:**
Florida Administrative Code (F.A.C.) Chapter 62-761, previously 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

The required base line internal inspections have been completed and the future internal inspections have been scheduled based on the established corrosion rate of the tank bottoms. Future costs will be incurred for required 5 year external inspections and repairs.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
Work continued on miscellaneous maintenance of above ground fuel storage tanks and piping systems. All required API 653 external inspections have been completed for this year and all 2004 tank registration fees have been paid. Also, 4 tanks required painting and are in progress to and will be finished by the end of the year.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $485,412 or 105.4% higher than previously projected. This project includes performing required repairs identified during tank inspections. The variance is primarily due to an updated estimate of the costs associated with the required repairs and painting, based on the results of tank inspections.

**Project Progress Summary:**
This is an ongoing project. Each reporting period will include ongoing maintenance of above ground fuel storage tanks in accordance with F.A.C. Chapter 62-761.

**Project Projections:**
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $448,000.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Oil Spill Cleanup/Response Equipment - O&M
**Project No. 8a**
**Project Description:**
The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
Plan updates have continued to be performed and filed for all sites as required. Routine maintenance of all oil spill equipment has continued throughout the year as well as the performance of spill management drills including a corporate team drill and deployment drills throughout the system. There has also been training for some team members.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $41 or 0.0% higher than previously projected.

**Project Progress Summary:**
This is an ongoing project. Each reporting period will include ongoing maintenance of all oil spill equipment in accordance with OPA 90.

**Project Projections:**
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $165,996.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Low-Level Radioactive Waste Access Fees - O & M
**Project No. 9**
**Project Description:**
Florida Power & Light Company is required to pay Low-Level Waste Access fees for the development of a second regional disposal facility in order to be able to dispose of its low-level radioactive waste at the Barnwell, South Carolina, Low-Level Waste Disposal Site. No other disposal sites are available to FPL for disposal of low-level radioactive waste.

The Low-Level Waste Access fees are invoiced and paid quarterly. The fees are calculated and assessed according to a fixed formula that is applied to all Southeast Compact low-level waste generators. The amount of the fee depends upon the volume of the low-level waste that FPL disposes of at the Barnwell Low-Level Waste Disposal Facility vs. the volume of low-level waste disposes of at Barnwell by all Southeast Compact generators.

**Project Accomplishments:**
All activities are complete.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
None

**Project Progress Summary:**
Complete

**Project Projections:**
None

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** RCRA Corrective Action - O & M
**Project No. 13**
**Project Description:**
Under the Hazardous and Solid Waste Amendments of 1984 (amending the Resource Conservation and Recovery Act, or RCRA), the U.S. EPA has the authority; to require hazardous waste treatment facilities to investigate whether there have been releases of hazardous waste or constituents from non-regulated units on the facility site. If contamination is found to be present at levels that represent a threat to human health or the environment, the facility operator can be required to undertake "corrective action" to remediate the contamination. In April 1994, the U.S. EPA advised FPL that it intended to initiate RCRA Facility Assessments (RFA's) at FPL's nine former hazardous waste treatment facility sites. The RFA is the first step in the RCRA Corrective Action process. At a minimum, FPL will be responding to the agency's requests for information concerning the operation of these power plants, their waste streams, their former hazardous waste treatment facilities and their non-regulated Solid Waste Management Units (SWMU's). FPL may also conduct assessments of human health risk resulting from possible releases from the SWMU's in order to demonstrate that any residual contamination does not represent an undue threat to human health or the environment. Other response actions could include a voluntary clean-up or compliance with the agency's imposition of the full gamut of RCRA Corrective Action requirements, including RCRA Facility Investigation, Corrective Measures Study and Corrective Measures Implementation.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
EPA and the FDEP have agreed that no further action is required at the Fort Myers and Martin Power Plants. EPA and the FDEP agree that no further action is required at the Putnam Power Plant, except for the petroleum clean-up that is going forward under the FDEP District Office waste clean-up oversite. EPA issued a RCRA Section 3007 order for site wide corrective action activities at the Manatee, Sanford, Turkey Point and St. Lucie Power Plants. Currently the EPA and FDEP have set no dates for the site visits. FPL is involved in ongoing discussions with the EPA and FDEP regarding the 3007 Order.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $50,002 or 100.0% higher than previously projected. This variance is primarily due an increase in projected costs associated with the preparation of the Manatee and Sanford facilities for an assessment by the EPA. These expenditures are contingent upon receiving notification from EPA of the intent to move forward with the process and were not included in the original projections.

**Project Progress Summary:**
This is an ongoing project. The next Visual Site Inspection date is pending. No further action is required at Ft. Myers, Martin Power Plants and Putnam except for some petroleum clean up at Putnam.

**Project Projection:**
Estimated project expenditures for the period of January 2005 through December 2005 are expected to be $100,000.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** NPDES Permit Fees - O & M
**Project No. 14**
**Project Description:**
In compliance with State of Florida Rule 62-4.052, Florida Power & Light Company (FPL) is required to pay annual regulatory program and surveillance fees for any permits it requires to discharge wastewater to surface waters under the National Pollution Discharge Elimination System. These fees effect the Florida legislature's intent that the Florida Department of Environmental Protection's (FDEP) costs for administering the NPDES program be borne by the regulated parties, as applicable. The fees for each permit type are as set forth in the rule, with an effective date of May 1, 1995, for their implementation. After the first year, annual fees are due and payable to the FDEP by January 15th of each year.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
The NPDES permit fees were paid to the FDEP during the month of January for Power Generation facilities.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $8,602 or 6.4% higher than previously projected.

**Project Progress Summary:**
The NPDES permit fees were paid to the FDEP during the month of January for Power Generation facilities.

**Project Projections:**
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $156,400.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Disposal of Noncontainerized Liquid Waste - O&M
**Project 17a**
**Project Description:**
FPL manages ash from heavy oil fired power plants using a wet ash system. Ash from the dust collector and economizer is sluiced to surface ash basins. The ash sludge is then pH adjusted to precipitate metals. In order to comply with Florida Administrative Code 62-701.300 (10), the ash is then de-watered using a plate/frame filter-press in order to dispose of it in a Class I landfill or ship by railcar to a processing facility for beneficial reuse.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
Ash de-watering has been completed at Riviera. Currently processing material at Manatee, which will be completed in August 2004. Ash de-watering is planned for the rest of 2004 at Martin, Turkey Point, and Cape Canaveral.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $2,367 or 0.8% lower than previously projected.

**Project Progress Summary:**
This is an ongoing project. The frequency of basin clean out is a function of basin capacity and rate of sludge/ash generation. Typically, FPL generates 5,000 tons (@ 50% solids) of sludge per year.

**Project Projections:**
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $269,001.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title: Substation** Pollutant Discharge Prevention & Removal - O&M
**Project No. 19a, 19b, 19c**
**Project Description:**
Florida Statute Chapter 376 Pollutant Discharge Prevention and Removal requires that any person discharging a pollutant, defined as any commodity made from oil or gas, shall immediately undertake to contain, remove and abate the discharge to the satisfaction of the department. Florida Statute Chapter 403 holds it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. Additionally, the majority of activities will be conducted in Dade and Broward counties which adhere to county regulations as defined in municipal codes. This project includes the prevention and removal of pollutant discharges at FPL substations and will prevent further environmental degradation.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
Plan development started in 1997 and fieldwork is planned to continue through 2005. The majority of the completed work has been in Dade, Broward and Palm Beach counties. Regasketing and encapsulation work continues in the North Area and the West Areas with progress in Palm Beach County. The majority of remediation work has been performed in Miami-Dade County.

A total of 709 transformer locations have been remediated since 1997. A total of 407 transformers have been regasketed and 834 transformers have been encapsulated. Additionally 444 transmission breakers have been encapsulated.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be:

- 19a Project expenditures are estimated to be $34,386 or 3.0% higher than projected. The project was accelerated in the first half of the year to take advantage of good weather. Equipment clearances were obtained which would not be available during the storm season.
- 19b Project expenditures are estimated to be $21,012 or 2.8% higher than projected. The project was accelerated in the first half of the year to take advantage of good weather. Equipment clearances were obtained which would not be available during the storm season.
- 19c No variance is anticipated.

**Project Progress Summary:**
Miami-Dade County DERM determined that remediation and ground water monitoring were required by FPL to resolve issues at distribution substations where arsenic has been found in ground water. The regasketing and encapsulation phase of the project continues.

**Project Projections:**
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $1,513,168.

# FLORIDA POWER & LIGHT COMPANY
# PROJECT DESCRIPTION AND PROGRESS

**Project Title:** Wastewater/Stormwater Discharge Elimination & Reuse - O&M
**Project 20a**
**Project Description:**
Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants and the Dade County DERM requires Turkey Point and Cutler Plant wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan Dade County.

In order to address these requirements, FPL has undertaken a multifaceted project which includes activities such as ash basin lining, installation of retention tanks, tank coating, sump construction, installation of pumps, motor, and piping, boiler blowdown recovery, site preparation, separation of stormwater and ashwater systems, separation of potable and service water systems, and the associated engineering and design work to implement these projects.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
On hold until further analysis can be obtained.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $40,000 or 80.0% lower than projected. The installation of the Electrostatic Precipitators (ESPs) at the Port Everglades Plant may result in less ash sluice water going to treatment basins, thereby reducing the amount of treated ash sluice water available for reuse. Once the ESP is operational, analyses will be performed to determine the amount of sluice water available for reuse at the plant. This project will be deferred until information resulting from the analyses is obtained.

**Project Progress Summary:**
On hold until further analysis can be obtained.

**Project Projections:**
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $0.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Pipeline Integrity Management (PIM) – O&M
**Project No.22**
**Project Description:**
FPL is required to develop a written pipeline integrity management program for its hazardous liquid pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
The baseline assessments were undertaken for the Martin 18" and 30" pipelines and associated evaluation is underway.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $180,225 or 450.5% higher than projected. A failure and oil spill at the Martin 30" pipeline required a response and repair. In order to ensure the integrity of the pipeline following repair, a complete analysis of the pipeline was required. This analysis was originally projected for 2005 but was accelerated.

**Project Progress Summary:**
This is an ongoing project. The baseline assessments are 60% complete at this time and the final evaluations are pending. These assessments are expected to be complete by the end of 2004.

**Project Projections:**
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $175,000.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** SPCC (spill prevention, control, and countermeasures) – O&M
**Project No.23a**
**Project Description:**
The EPA first established the SPCC Program in 1973 when the agency issued the Oil Pollution Prevention Regulation (i.e., SPCC rule) to address the oil spill prevention provisions contained in the Federal Water Pollution Control Act of 1972 (later amended as the Clean Water Act). The purpose of the regulation was to prevent discharges of oil from reaching the navigable waters of the U.S. or adjoining shorelines and to prepare facility personnel to respond to oil spills. The SPCC regulation requires certain facilities to prepare and implement SPCC Plans and address oil spill prevention requirements including the establishment of procedures, methods, equipment, and other requirements to prevent discharges of oil as described above. Specifically, the rule applies to any owner or operator of a non-transportation related facility that:

- Has a combined aboveground oil storage capacity of more than 1320 gallons, or a total underground oil storage capacity exceeding 42,000 gallons (Note: the underground storage capacity does not apply to those tanks subject to all of the technical requirements of the federal underground storage tank rule found in 40 CFR 280 or a State approved program); and

- Which due to its location, could be reasonably expected to discharge oil in quantities that may be harmful into or upon the navigable waters of the United States or adjoining shorelines.

In January 1988, a large storage tank owned by Ashland Oil Company at a site in western Pennsylvania collapsed, releasing approximately 750,000 gallons of diesel fuel to the Monongahela River. Following calls for new tank legislation, an EPA task force recommended expanded regulation of aboveground tanks within the framework of existing legislative authority. The result was EPA's SPCC rulemaking package, the first phase of which was proposed in 1991. Due to a series of agency delays primarily resulting from the 1989 Exxon Valdez oil spill that required EPA to issue the Facility Response Plan rule under the Oil Pollution Act of 1990, the final SPCC Rule was not published until July of 2002.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
The drawings required to support the SPCC plan updates for all the plants and fuel terminals should be completed in the third quarter. The updated SPCC plans are scheduled to be completed by the end of the year, ready for internal reviews. A majority of the internal reviews are also scheduled to be completed by the end of the year. It is anticipated that the project will have all the required upgrades identified by the end of the year.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $64,571 or 25.8% lower than projected. The EPA has extended the deadlines for SPCC compliance. SPCC Plans will now be due in August 2005 and the facility upgrades will be due in February 2006. Costs associated with the development of SPCC plans, which were included in the original projections, have shifted to 2005.

**Project Progress Summary:**
By the end of 2004, we plan to have all required drawings updated, and the updated SPCC plans complete and ready for internal review. A majority of the internal reviews should also be complete, as well as the identification of required plant upgrades. It should be noted that the EPA has changed the due date for updating the SPCC plans from August 2004 to August 2005.

**Project Projections:**
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $124,808.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Manatee Reburn – O&M
**Project No.24a**
**Project Description:**
This project involves installation of reburn technology in Manatee Units 1 and 2. Reburn is an advanced nitrogen oxides (NOx) control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers. The process is a proven advanced technology, with applications of a reburn-like flue gas incineration technique dating back to the late 1960s, and developments for applications to large coal fired power plants in the United States dating back to the early to mid 1980s.

Reburn is an in-furnace NOx control technology that employs fuel staging in a configuration where a portion of the fuel is injected downstream of the main combustion zone to create a second combustion zone, called the reburning zone. The reburning zone is operated under conditions where NOx from the main combustion zone is converted to elemental nitrogen (which makes up 79% of the atmosphere). The basic front wall-fired boiler reburning process is shown conceptually in Figure 1 (see below), and divides the furnace into three zones.

In the 1996-97 time period, FPL invested a considerable effort evaluating the Manatee Units for the application of reburn technology. FPL has recently reviewed the reburn system designs previously proposed for the Manatee units, and concluded that a design for either oil or gas reburn would require very similar characteristics. This will require reburn fuel injectors to be located at the elevation of the present top row of burners, with reburn injectors on the boiler front and rear walls. For the present application the injectors will be required to have a dual fuel (oil and gas) capability. In order to provide adequate residence time for the reburn process, it is proposed to locate the reburn overfire air (OFA) ports between the boiler wing walls and to angle them slightly to provide better mixing with the boiler flow. Because of the complexity of the boiler flow field and the port location, it was determined that OFA booster fans would be required to assist the air-fuel mixing and complete the burnout process. Installation of reburn technology for Manatee Units 1 and 2 offers the potential to reduce NOx emissions through a "pollution prevention" approach that does not require the use of reagents, catalysts, pollution reduction or removal equipment. FDEP and FPL agree that reburn technology is the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
The Manatee Reburn project for O&M is in its early stages and FPL has put together cost estimates, looked at alternatives for NOx control technology, and worked with the Florida Department of Environmental Protection to reach an agreement to ensure compliance with ozone ambient air quality standards in the Tampa Bay Airshed.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
None

**Project Progress Summary:**
None for the O&M portion of the Manatee Reburn Project.

**Project Projections:**
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $0.

# FLORIDA POWER & LIGHT COMPANY
# PROJECT DESCRIPTION AND PROGRESS

**Project Title:** UST Replacement/Removal – O&M
**Project No.26**
**Project Description:**
The Florida Administrative Code (FAC) Chapter 62-761.500, dated July 13, 1998, requires the removal or replacement of existing Category-A and Category-B storage tank systems with systems meeting the standards of Category-C storage tank systems by December 31, 2009. UST's Category-A is single-walled tanks or underground single-walled piping with no secondary containment that was installed before June 30, 1992.

UST's Category-B is tanks containing pollutants after June 30, 1992 or a hazardous substance after January 1, 1994 that shall have a secondary containment. Small diameter piping that comes in contact with the soil that is connected to a UST that shall have secondary containment if installed after December 10, 1990.

UST's and AST's for Category-C under F.A.C. 62-761.500 are tanks that shall have some or all of the following; a double wall, be made of fiberglass, have exterior coatings that protect the tank from external corrosion, secondary containment (e.g., concrete walls and floor) for the tank and the piping, and overfill protection.

FPL has six Category-A and two Category-B Storage Tank Systems that must be removed or replaced in order to meet the performance standards of Rule 61-761.500. In 2004 FPL will replace the two single-walled USTs located at the Turkey Point Nuclear Plant Units 1 and 2 with ASTs providing secondary containment (concrete walls and floor) surrounding the tanks. Also in 2004, FPL will remove one single-walled UST located at the Ft. Lauderdale Plant and will not replace the tank. In 2005-2006 FPL will replace the single-walled USTs located at the Area Office Broward (one UST in 2005), Customer Service East Office (one UST in 2006), Juno Beach Office (one UST in 2005), and General Office (2 USTs in 2005), with double-walled tanks providing electronic leak detection. Additionally, the AST to be installed at the Area Broward Office will be concrete vaulted.

The removal and replacement of the USTs will be performed by outside contractors. Additionally, closure assessments will be performed in accordance with 62-761.800 and closure assessment reports will be submitted to local Counties, and the Department of Environmental Services (DEP).

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
Initial review of the scope of work has been completed. The Nuclear Division's portion of the project is expected to begin in July and be completed in September 2004.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
No variance is expected.

**Project Progress Summary:**
Initial review of the scope of work has been completed.

**Project Projections:**
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $568,000.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Lowest Quality Water Source (LQWS) – O&M
**Project No. 27**
**Project Description:**
Section 366.8255 of the Florida Statutes provides for the recovery through the ECRC of "environmental compliance costs," which are costs incurred in complying with "environmental rules or regulations." As I explain below, the LQWS Project is required in order to comply with permit conditions in the Consumptive Use Permits (CUPs) issued by the St. Johns River Water Management District (SJRWMD or the District)) for the Sanford and Cape Canaveral Plants. Those permit conditions are intended to preserve Florida's groundwater, which is an important environmental resource. The permit conditions therefore "apply to electric utilities and are designed to protect the environment" as contemplated by section 366.8255. The SJRWMD adopted a policy in 2000 that, upon permit renewal, a user of the District's water is required to use the lowest quality of water that is technically, environmentally and economically feasible for its needs. This policy was implemented for the Sanford and Cape Canaveral Plants in their current CUPs. For the Sanford facility, Condition 15 of CUP No. 9202, issued in June 2000, requires the lowest quality of water to be used that is feasible to meet the needs of the facility. The requirement for the Cape Canaveral Plant is found in Conditions 14 and 15 of CUP No. 10652, issued October 2001, which address the quantity of reclaimed water to be used and require that all available reclaimed water be used prior to groundwater.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
The project at Sanford is currently operational. Waiting on final approval from DEP for our discharge permit at Cape Canaveral Plant.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance of $68,370 or 18.5% lower than higher than projected. This variance is primarily due to a delay in the permitting for the Reclaimed Water Use at the Cape Canaveral Plant. The plant was not able to use the lowest quality water source during the first and second quarters of 2004 which resulted in lower than projected expenditures.

**Project Progress Summary:**
(January 2004 - December 2004)
The project at Sanford is currently operational. Waiting on final approval from DEP for our discharge permit at Cape Canaveral Plant.

**Project Projections:**
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $378,000.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** CWA 316(b) Phase II Rule - O&M
**Project No. 28**
**Project Description:**
The Phase II rule implements section 316 (b) of the Clean Water Act (CWA) for certain existing power plants that employ a cooling water intake structure and that withdraw 50 million gallons per day (MGD) or more of water from rivers, streams, lakes, reservoirs, estuaries, oceans or other waters of the United States (WUS) for cooling purposes. It constitutes Phase II in the United States Environmental Protection Agency's (EPA) development of section 316 (b) regulations and establishes national requirements applicable to, and that reflect the best technology available (BTA) for, the location, design, construction and capacity of existing cooling water intake structures (CWIS) to minimize adverse environmental impact. It is anticipated that this Phase II Rule will potentially impact the following FPL facilities: Cape Canaveral, Cutler, Fort Myers, Ft. Lauderdale, Port Everglades, Riviera, Sanford (Unit 3 only) and St. Lucie Power Plants.

**Project Accomplishments:**
This project is in the early stages and information gathering should start by September 2004.

**Project Fiscal Expenditures:**
Nothing has been spent so far but we expect to spend $500,000 by year-end.

**Project Progress Summary:**
This project is in the early stages and information gathering should start by September 2004. Vendors are being selected in August 2004.

**Project Projections:**
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $2,327,196.

# FLORIDA POWER & LIGHT COMPANY
# PROJECT DESCRIPTION AND PROGRESS

**Project Title:** Low NOx Burner Technology - Capital
**Project No. 2**
**Project Description:**
Under Title I of the Clean Air Act Amendments of 1990, Public Law 101-349, utilities with units located in areas designated as "non-attainment" for ozone will be required to reduce $NO_x$ emissions. The Dade, Broward and Palm Beach county areas were classified as "moderate non-attainment" by the EPA. FPL has six units in this affected area.

LNBT meets the requirement to reduce $NO_x$ emissions by delaying the mixing of the fuel and air at the burner, creating a staged combustion process along the length of the flame. $NO_x$ formation is reduced because peak flame temperatures and availability of oxygen for combustion is reduced in the initial stages.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
All six units are in service and operational.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is estimated to be $10,495 or 0.5% lower than projected.

**Project Progress Summary:**
Dade, Broward and Palm Beach Counties have now been redesignated as "attainment" for ozone with air quality maintenance plans. This redesignation still requires that all controls, such as LNBT, placed in effect during the "non-attainment" be maintained.

The LNBT burners are installed at all of the six units and design enhancements are complete.

**Project Projections:**
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $1,911,206.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Continuous Emission Monitoring System (CEMS) - Capital
**Project No. 3b**
**Project Description:**
The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping and reporting of $SO_2$, $NO_x$ and carbon dioxide ($CO_2$) emissions, as well as volumetric flow, heat input, and opacity data from affected air pollution sources. FPL has 36 units which are affected and which have installed CEMS to comply with these requirements.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMS and specific requirements for the monitoring of pollutants, opacity, heat input, and volumetric flow. These regulations are very comprehensive and specific as to the requirements for CEMS, and in essence, they define the components needed and their configuration. Periodically, these systems extract and analyze gaseous samples for each power plant stack and have automated data acquisition and reporting capability.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
NOx Continuos Emission Monitoring analyzers were installed at all fossil facilities.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is $46,634, or 3.2% lower than projected. $126,336 of CEMS equipment retirements at various plants were not included in the original projections. Additionally, $473,948 of 7-year amortizable CEMS equipment retirements are estimated for August 2004 which were not included in the original projections.

**Project Progress Summary:**
The project is complete. All upgrades were done by April 2004.

**Project Projections:**
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $1,522,752.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Clean Closure Equivalency – Capital
**Project No.4b**
**Project Description:**
In compliance with 40 CFR 270.1(c)(5) and (6), FPL developed CCED's for nine FPL power plants to demonstrate to the U.S. EPA that no hazardous waste or hazardous constituents remain in the soil or water beneath the basins which had been used in the past to treat corrosive hazardous waste. The basins, which are still operational as part of the wastewater treatment systems at these plants, are no longer used to treat hazardous waste.

To demonstrate clean closure, soil sampling and ground water monitoring plans, implementation schedules, and related reports must be submitted to the EPA. Capital costs are for the installation of monitoring wells (typically four per site) necessary to collect ground water samples for analysis.

**Project Accomplishments:**
(January 1, 2003 to December 31, 2003)
All activities are complete.

**Project Fiscal Expenditures:**
(January 1, 2003 to December 31, 2003)
The variance in depreciation and return is estimated to be $22 or 0.4% lower than projected.

**Project Progress Summary:**
Complete

**Project Projections:**
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $6,154.

# FLORIDA POWER & LIGHT COMPANY
# PROJECT DESCRIPTION AND PROGRESS

**Project Title:** Maintenance of Stationary Above Ground Fuel Storage Tanks – Capital
**Project No.5b**
**Project Description:**
Florida Administrative Code (F.A.C.) Chapter 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

The capital project associated with complying with the new standards includes the installation of items for each tank such as liners, cathodic projection systems and tank high-level alarms.

**Project Accomplishments:**
(January 1, 2003 to December 31, 2003)
The double bottom has been installed in tank 901 at Port Everglade's plant and this job is final. The installation of the double bottom in 902 at Port Everglade's plant is complete. The Riviera Plant B tank internal API 653 inspection has been completed and the tank returned to service.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return of $98,519, or 6.1% lower than projected is primarily due to actual retirements of $531,139 for the Port Everglades GT units. These retirements were not included in the original projections.

**Project Progress Summary:**
FPL has completed initial inspections and upgrades for all of its tanks. Two of the storage tanks located at the Port Everglades Terminal needed to be retrofitted with new double bottoms because the initial FDEP approved method for double bottom leak detection system used by FPL has failed over the past two years. These are complete. FPL has obtained alternate procedures from the Florida Department of Environmental Protection to install these double bottom leak detection systems along with additional alarms and valve containment systems for the light oil tanks in lieu of secondary containment dike liners. The alternate procedures may be rescinded by FDEP in the next couple of years. Additionally, the Riviera plant B tank was due for an internal API 653 inspection in 2004. This inspection and associated repairs have been completed.

**Project Projections:**
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $1,887,050.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Relocate Turbine Lube Oil Underground Piping to Above Ground – Capital
**Project No. 7**
**Project Description:**
In accordance with criteria contained in Chapter 62-762 of the Florida Administrative Code (F.A.C.) for storage of pollutants, FPL initiated the replacement of underground Turbine Lube Oil piping to above ground installations at the St. Lucie Nuclear Power Plant.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
All activities are complete.

**Project Fiscal Expenditures:**
The variance in depreciation and return is estimated to be $14 or 0.4% lower than projected.

**Project Progress Summary:**
This project is complete.

**Project Projections:**
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $3,306.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Oil Spill Cleanup/Response Equipment – Capital
**Project No. 8b**
**Project Description:**
The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
All equipment is being maintained and replaced according to capital budgeting requirements in order to maintain compliance with regulatory guidelines for response readiness.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return of $26,484 or 18.7% lower than projected is primarily due to $86,208 of 7-year amortizable retirements at Martin common, which are now estimated to occur in August 2004. These retirements were not included in the original projections.

**Project Progress Summary:**
All deadlines, both state and federal, have been met. Ongoing costs will be annual in nature and will consist of equipment upgrades/replacements.

**Project Projections:**
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $133,083.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Relocate Storm Water Runoff – Capital
**Project No.10**
**Project Description:**
The new National Pollutant Discharge Elimination System (NPDES) permit, Permit No. FL0002206, for the St. Lucie Plant, issued by the United States Environmental Protection Agency contains new effluent discharge limitations for industrial-related storm water from the paint and land utilization building areas. The new requirements become effective on January 1, 1994. As a result of these new requirements, the effected areas will be surveyed, graded, excavated and paved as necessary to clean and redirect the storm water runoff. The storm water runoff will be collected and discharged to existing water catch basins on site.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
All activities are complete.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is estimated to be $29 or 0.3% lower than projected.

**Project Progress Summary:**
Complete

**Project Projections:**
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $12,852.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Scherer Discharge Pipeline – Capital
**Project No.12**
**Project Description:**
On March 16, 1992, pursuant to the provisions of the Georgia Water Quality control Act, as amended, the Federal Clean Water Act, as amended, and the rules and regulations promulgated thereunder, the Georgia Department of Natural Resources issued the National Pollutant Discharge Elimination System (NPDES) permit for Plant Scherer to Georgia Power Company. In addition to the permit, the Department issued Administrative Order EPD-WQ-1855 which provided a schedule for compliance by April 1, 1994 with new facility discharge limitations to Berry Creek. As a result of these new limitations, and pursuant to the order, Georgia Power Company was required to construct an alternate outfall to redirect certain wastewater discharges to the Ocmulgee River. Pursuant to the ownership agreement with Georgia Power Company for Scherer Unit 4, FPL is required to pay for its share of construction of the discharge pipeline which will constitute the alternate outfall.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
All activities are complete.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is estimated to be $284 or 0.3% lower than projected.

**Project Progress Summary:**
Complete

**Project Projections:**
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $94,522.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Disposal of Non-Contaminated Liquid Waste – Capital
**Project No.17b**
**Project Description:**
FPL manages ash from heavy oil fired power plants using a wet ash system. Ash from the dust collector and economizer is sluiced to surface ash basins. The ash sludge is then pH adjusted to precipitate metals. In order to comply with Florida Administrative Code 62-701.300 (10), the ash is then de-watered using a plate/frame filter-press in order to dispose of it in a Class I landfill or ship by railcar to a processing facility for beneficial reuse.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
All activities are complete.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance of $3,025 or 11.0% lower than projected is primarily due to $311,009 of 7-year amortizable retirements of general plant equipment which are now estimated to occur in August 2004. These retirements were not included in the original projections.

**Project Progress Summary:**
Complete

**Project Projections:**
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $0.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Wastewater Discharge Elimination & Reuse – Capital
**Project No.20**
**Project Description:**
Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants and the Dade County DERM requires Turkey Point and Cutler Plant wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan Dade County.

In order to address these requirements, FPL has undertaken a multifaceted project which includes activities such as ash basin lining, installation of retention tanks, tank coating, sump construction, installation of pumps, motor, and piping, boiler blowdown recovery, site preparation, separation of stormwater and ashwater systems, separation of potable and service water systems, and the associated engineering and design work to implement these projects.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
All activities are complete.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is $79,207 or 28.7% lower than projected. This variance is primarily due to timing differences. Wastewater reuse system installations at the Martin and Cape Canaveral Plants, which were originally projected to go in-service in January 2004, are now projected for December 2004.

**Project Progress Summary:**
Complete

**Project Projections:**
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $276,883.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Turtle Net at St Lucie Nuclear Plant – Capital
**Project No.21**
**Project Description:**
The Turtle Net project says that FPL is limited in the number of lethal turtle takings permitted at its St. Lucie Power Plant by the Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on May 4, 2001 by the National Marine Fisheries Service ("NMFS"). The number of lethal takings permitted in a given year is calculated by taking one percent of the total number of loggerhead and green turtles captured in that year. (The Incidental Take Statement separately limits the number of lethal takings of Kemp's Ridley turtles to two per year over the next ten years, and the number of lethal takings of either hawksbill or leatherback turtles to one of those species every two years over the next ten years). Based on the number of captured turtles in 2001, the lethal take limit for loggerhead and green turtles in that year was six (references; Nuclear Regulatory Commission letter dated May 18, 2001 included as Exhibit 1, Document No. 1, Endangered Species Act Section 7 Consultation Biological Opinion Incidental Take Statement dated May 4, 2001 included as Exhibit 1, Document No. 2, Appendix B To Facility Operating License No. NPF-16 St. Lucie Unit 2, Environmental Protection Plan, Non-Radiological, Amendment No. 103 included as Exhibit 1, Document No. 3). In 2001, FPL experienced six lethal takings of loggerhead and green turtles at the St. Lucie Power Plant, indicating that its existing measures to limit such takings were performing marginally.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
The Turtle Net Project has been fully completed in November 2002.

**Project Fiscal Expenditures:**
(January 1, 2004 – December 31, 2004)
The variance in depreciation and return is $207 or 0.2% lower than projected.

**Project Progress Summary:**
Complete

**Project Projections:**
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $98,294 of capital.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Pipeline Integrity Management (PIM) – Capital
**Project No.22**
**Project Description:**
FPL is required to develop a written pipeline integrity management program for its hazardous liquid pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
This project is in the conceptual design phase and the design should be complete by year-end. Once this is done it will be put out to bid.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is $99,690 or 98.5% lower than projected. This variance is primarily due to the deferral of most of the work planned for 2004 to 2005. The hydraulic study and meter testing for the Martin 30" pipeline was completed and results determined that the installation of positive displacement meters was required. These meters needed to be special ordered. Additionally, the study and testing determined that some of the pipeline system needs to be modified with new valves and piping to accommodate the meter system as well as some instrumentation. The meters are a long lead time item and due to the lead time and requirements for having to take the 30" pipeline out of service to perform the work it was determined that this work needed to be moved to 2005.

**Project Progress Summary:**
This is an ongoing project. Step two is the baseline assessment plan and it is well on the way. Step three is next which is information analysis will also include the installation of some equipment on FPL's 30" Martin pipeline and this should begin in January 2005.

**Project Projections:**
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $94,974.

# FLORIDA POWER & LIGHT COMPANY
# PROJECT DESCRIPTION AND PROGRESS

**Project Title:** SPCC (spill prevention, control, and countermeasures) – Capital
**Project No.23b**
**Project Description:**
The EPA first established the SPCC Program in 1973 when the agency issued the Oil Pollution Prevention Regulation (i.e., SPCC rule) to address the oil spill prevention provisions contained in the Federal Water Pollution Control Act of 1972 (later amended as the Clean Water Act). The purpose of the regulation was to prevent discharges of oil from reaching the navigable waters of the U.S. or adjoining shorelines and to prepare facility personnel to respond to oil spills. The SPCC regulation requires certain facilities to prepare and implement SPCC Plans and address oil spill prevention requirements including the establishment of procedures, methods, equipment, and other requirements to prevent discharges of oil as described above. Specifically, the rule applies to any owner or operator of a non-transportation related facility that:

- Has a combined aboveground oil storage capacity of more than 1320 gallons, or a total underground oil storage capacity exceeding 42,000 gallons (Note: the underground storage capacity does not apply to those tanks subject to all of the technical requirements of the federal underground storage tank rule found in 40 CFR 280 or a State approved program); and

- Which due to its location, could be reasonably expected to discharge oil in quantities that may be harmful into or upon the navigable waters of the United States or adjoining shorelines.

In January 1988, a large storage tank owned by Ashland Oil Company at a site in western Pennsylvania collapsed, releasing approximately 750,000 gallons of diesel fuel to the Monongahela River. Following calls for new tank legislation, an EPA task force recommended expanded regulation of aboveground tanks within the framework of existing legislative authority. The result was EPA's SPCC rulemaking package, the first phase of which was proposed in 1991. Due to a series of agency delays primarily resulting from the 1989 Exxon Valdez oil spill that required EPA to issue the Facility Response Plan rule under the Oil Pollution Act of 1990, the final SPCC Rule was not published until July of 2002.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
The major projects which will be completed by the Power Generation Division in 2004 are:
Riviera Plant – Double walling of fuel oil piping
Lauderdale Plant – Secondary containment liner on tanks 2, 3 & 5 and double wall fuel oil piping
Putnam Plant – Secondary containment liner tanks C-G and double walling of fuel oil piping
Ft Myers Plant – Secondary containment liner tanks 1 & 2
Lauderdale Plant – Secondary containment liner tanks 901 & 902 & Double wall fuel oil piping

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is $376,102 or 28.0% lower than projected. This variance is primarily due to the timing of additions, which resulted in the average plant balance being lower than originally projected. Projects that were originally anticipated to go in-service during the prior reporting period will now be placed in service this reporting period. The reduction in the average plant balance due to timing differences was partially offset by the additional of activities (double-wall fuel oil piping at Riviera Plant Units 3 and 4, Sanford Plant Unit 3, and Cape Canaveral Plant, and fuel oil piping sheet pile diversion at Manatee Plant) which were not included in the original projections.

**Project Progress Summary:**
The Power Generation Division is on schedule for completing all the required modifications at the power plant sites in order to comply with revised spill prevention control & countermeasure rule.

**Project Projections:**
Estimated project expenditures (depreciation and return) for Power Systems and Power Generation, for the period January 2005 through December 2005 are expected to be $2,287,880.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Manatee Reburn – Capital
**Project No.24**
**Project Description:**
This project involves installation of reburn technology in Manatee Units 1 and 2. Reburn is an advanced nitrogen oxides (NOx) control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers. The process is a proven advanced technology, with applications of a reburn-like flue gas incineration technique dating back to the late 1960s, and developments for applications to large coal fired power plants in the United States dating back to the early to mid 1980s.

Reburn is an in-furnace NOx control technology that employs fuel staging in a configuration where a portion of the fuel is injected downstream of the main combustion zone to create a second combustion zone, called the reburning zone. The reburning zone is operated under conditions where NOx from the main combustion zone is converted to elemental nitrogen (which makes up 79% of the atmosphere). The basic front wall-fired boiler reburning process is shown conceptually in Figure 1 (see below), and divides the furnace into three zones.

In the 1996-97 time period, FPL invested a considerable effort evaluating the Manatee Units for the application of reburn technology. FPL has recently reviewed the reburn system designs previously proposed for the Manatee units, and concluded that a design for either oil or gas reburn would require very similar characteristics. This will require reburn fuel injectors to be located at the elevation of the present top row of burners, with reburn injectors on the boiler front and rear walls. For the present application the injectors will be required to have a dual fuel (oil and gas) capability. In order to provide adequate residence time for the reburn process, it is proposed to locate the reburn overfire air (OFA) ports between the boiler wing walls and to angle them slightly to provide better mixing with the boiler flow. Because of the complexity of the boiler flow field and the port location, it was determined that OFA booster fans would be required to assist the air-fuel mixing and complete the burnout process. Installation of reburn technology for Manatee Units 1 and 2 offers the potential to reduce NOx emissions through a "pollution prevention" approach that does not require the use of reagents, catalysts, pollution reduction or removal equipment. FDEP and FPL agree that reburn technology is the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
Bid evaluation of potential Reburn Contractors is complete and a preferred contractor has been selected, pending the results of final negotiations, we are expecting a signed contract by the end of September 2003. If a contract is consummated in September, we would expect process and detail design to be approximately 30% complete by year end. We have expended approximately $110,000.00 in contracted in-house Reburn related modeling studies.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is estimated to be $299,991 or 97.8% higher than projected. This variance is due to timing differences - a larger portion of the expenditures being made in the earlier months of 2004 which were projected to be made later in the year, thereby increasing the return on investment.

**Project Progress Summary:**
The engineers and contractors are in the process of reviewing detail design and should be approximately 30% complete by year-end.

**Project Projections:**
Estimated project expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $1,852,914.

**FLORIDA POWER & LIGHT COMPANY**
**PROJECT DESCRIPTION AND PROGRESS**

**Project Title:** Pt. Everglades ESP Technology – Capital
**Project No.25**
**Project Description:**
The requirements of the Clean Air Act direct the EPA to develop health-based standards for certain "criteria pollutants". i.e. ozone ($O_3$), sulfur dioxide ($SO_2$), carbon monoxide (CO), particulate matter (PM), nitrogen oxides (NOx), an lead (Pb). EPA developed standards for the criteria pollutants and regulates the emissions of those pollutants from major sources by way of the Title V permit program. Florida has been granted authority from the EPA to administer its own Title V program which is at least as stringent as the EPA requirements. Florida is able to, issue, renew and enforce Title V air operating permits for sources within the state via 403.061 Florida Statutes and Chapter 62-213 F.A.C., which is administered by the State of Florida Department of Environmental Protection ("DEP"). The Title V program addresses the six criteria pollutants mentioned earlier, and includes hazardous air pollutants (HAP). The EPA sets the limits of emissions of Hazardous Air Pollutants through the Maximum Achievable Control Technology (MACT). The original Port Everglades Title V permit, issued in 1998, expires on December 31, 2003 and must be renewed. The DEP's Final Title V permit for FPL Port Everglades plant requires FPL to install Electrostatic Precipitators at all four Port Everglades units to address local concerns and to insure compliance with the National Ambient Air Quality Stands and the EPA MACT Standards.

**Project Accomplishments:**
(January 1, 2004 to December 31, 2004)
The engineering design for Units 1–4 will be completed in 2004. Construction work is on schedule to support the start up of the Unit 2 electrostatic precipitator in the spring of 2005 and the Unit 1 electrostatic precipitator in the fall of 2005.

**Project Fiscal Expenditures:**
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is estimated to be $228,739 or 20.9% lower than projected. This variance is due to timing differences - a larger portion of the expenditures being made in the later months of the year which were projected to be made earlier in the year, thereby decreasing the return on investment.

**Project Progress Summary:**
(January 2004 - December 2004)
The engineering design for Units 1–4 will be completed in 2004. Construction work is on schedule to support the start up of the Unit 2 electrostatic precipitator in the spring of 2005 and the Unit 1 electrostatic precipitator in the fall of 2005.

**Project Projections:**
Estimated project expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $5,741,303.

Form 42-6P

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % By Rate Class
January 2005 to December 2005

| Rate Class | (1) Avg 12 CP Load Factor at Meter (%) | (2) GCP Load Factor at Meter (%) | (3) Projected Sales at Meter (KWH) | (4) Projected Avg 12 CP at Meter (KW) | (5) Projected GCP at Meter (KW) | (6) Demand Loss Expansion Factor | (7) Energy Loss Expansion Factor | (8) Projected Sales at Generation (KWH) | (9) Projected Avg 12 CP at Generation (kW) | (10) Projected GCP Demand at Generation (kW) | (11) Percentage of KWH Sales at Generation (%) | (12) Percentage of 12 CP Demand at Generation (%) | (13) Percentage of GCP Demand at Generation (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RS1/RST1 | 63.060% | 58.556% | 55,334,940,634 | 10,017,085 | 10,787,651 | 1.09230267 | 1.07281827 | 59,364,335,282 | 10,941,689 | 11,783,380 | 53.79073% | 59.77947% | 57.80470% |
| GS1/GST1 | 69.973% | 59.323% | 6,075,542,153 | 991,175 | 1,169,108 | 1.09230267 | 1.07281827 | 6,517,952,622 | 1,082,663 | 1,277,020 | 5.90599% | 5.91508% | 6.26457% |
| GSD1/GSDT1 | 77.702% | 67.808% | 23,085,553,190 | 3,391,595 | 3,886,466 | 1.09220064 | 1.07274057 | 24,764,809,488 | 3,704,302 | 4,244,801 | 22.43969% | 20.23830% | 20.82335% |
| OS2 | 93.228% | 18.954% | 21,113,200 | 2,585 | 12,716 | 1.05829225 | 1.04657532 | 22,096,554 | 2,736 | 13,457 | 0.02002% | 0.01495% | 0.06601% |
| GSLD1/GSLDT1/CS1/CST1 | 83.923% | 73.179% | 10,666,361,079 | 1,450,879 | 1,663,887 | 1.09083728 | 1.07170069 | 11,431,146,528 | 1,582,673 | 1,815,030 | 10.35790% | 8.64687% | 8.90383% |
| GSLD2/GSLDT2/CS2/CST2 | 87.158% | 77.697% | 1,750,619,663 | 229,288 | 257,208 | 1.08297958 | 1.06544968 | 1,865,197,160 | 248,314 | 278,551 | 1.69008% | 1.35665% | 1.36646% |
| GSLD3/GSLDT3/CS3/CST3 | 86.580% | 74.020% | 187,194,635 | 24,682 | 28,869 | 1.02969493 | 1.02438901 | 191,760,127 | 25,415 | 29,726 | 0.17376% | 0.13885% | 0.14582% |
| ISST1D | 96.676% | 65.398% | 0 | 0 | 0 | 1.09230267 | 1.07281827 | 0 | 0 | 0 | 0.00000% | 0.00000% | 0.00000% |
| ISST1T | 87.151% | 34.593% | 0 | 0 | 0 | 1.02969493 | 1.02438901 | 0 | 0 | 0 | 0.00000% | 0.00000% | 0.00000% |
| SST1T | 87.151% | 34.593% | 150,031,028 | 19,652 | 49,510 | 1.02969493 | 1.02438901 | 153,690,136 | 20,236 | 50,980 | 0.13926% | 0.11056% | 0.25009% |
| SST1D1/SST1D2/SST1D3 | 96.676% | 65.398% | 23,594,871 | 2,786 | 4,119 | 1.07224837 | 1.06763473 | 25,190,703 | 2,987 | 4,417 | 0.02283% | 0.01632% | 0.02167% |
| CILC D/CILC G | 92.072% | 85.089% | 3,469,946,584 | 430,221 | 465,526 | 1.08128023 | 1.06432600 | 3,693,154,368 | 465,189 | 503,364 | 3.34641% | 2.54154% | 2.46931% |
| CILC T | 94.419% | 84.681% | 1,522,653,717 | 184,093 | 205,263 | 1.02969493 | 1.02438901 | 1,559,789,734 | 189,560 | 211,358 | 1.41334% | 1.03565% | 1.03684% |
| MET | 70.123% | 58.555% | 96,643,843 | 15,733 | 18,841 | 1.05829225 | 1.04657532 | 101,145,061 | 16,650 | 19,939 | 0.09165% | 0.09097% | 0.09781% |
| OL1/SL1/PL1 | 565.360% | 48.204% | 555,624,734 | 11,219 | 131,580 | 1.09230267 | 1.07281827 | 596,084,366 | 12,255 | 143,725 | 0.54012% | 0.06695% | 0.70506% |
| SL2 | 99.953% | 96.512% | 70,174,667 | 8,015 | 8,300 | 1.09230267 | 1.07281827 | 75,284,665 | 8,755 | 9,066 | 0.06822% | 0.04783% | 0.04447% |
| TOTAL | | | 103,009,994,000 | 16,779,008 | 18,689,044 | | | 110,361,636,795 | 18,303,424 | 20,384,814 | 100.00% | 100.00% | 100.00% |

Notes:
(1) AVG 12 CP load factor based on actual load research data
(2) GCP load factor based on actual load research data
(3) Projected KWH sales for the period January 2005 through December 2005
(4) Calculated: (Col 3)/(8,760 * Col 1)
(5) Calculated: (Col 3)/8,760 * Col 2)
(6) Based on 2003 demand losses
(7) Based on 2003 energy losses
(8) Col 3 * Col 7
(9) Col 1 * Col 6
(10) Col 2 * Col 6
(11) Col 8 / total for Col 8
(12) Col 9 / total for Col 9
(13) Col 10 / total for Col 10

Form 42-7P

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of Environmental Cost Recovery Clause Factors
January 2005 to December 2005

| Rate Class | (1) Percentage of KWH Sales at Generation (%) | (2) Percentage of 12 CP Demand at Generation (%) | (3) Percentage of GCP Demand at Generation (%) | (4) Energy Related Cost ($) | (5) CP Demand Related Cost ($) | (6) GCP Demand Related Cost ($) | (7) Total Environmental Costs ($) | (8) Projected Sales at Meter (KWH) | (9) Environmental Cost Recovery Factor ($/KWH) |
|---|---|---|---|---|---|---|---|---|---|
| RS1/RST1 | 53.79073% | 59.77947% | 57.80470% | $7,863,703 | $5,747,335 | $401,919 | $14,012,957 | 55,334,940,634 | 0.00025 |
| GS1/GST1 | 5.90599% | 5.91508% | 6.26457% | $863,401 | $568,690 | $43,558 | $1,475,649 | 6,075,542,153 | 0.00024 |
| GSD1/GSDT1 | 22.43969% | 20.23830% | 20.82335% | $3,280,473 | $1,945,757 | $144,786 | $5,371,016 | 23,085,553,190 | 0.00023 |
| OS2 | 0.02002% | 0.01495% | 0.06601% | $2,927 | $1,437 | $459 | $4,823 | 21,113,200 | 0.00023 |
| GSLD1/GSLDT1/CS1/CST1 | 10.35790% | 8.64687% | 8.90383% | $1,514,228 | $831,330 | $61,909 | $2,407,467 | 10,666,361,079 | 0.00023 |
| GSLD2/GSLDT2/CS2/CST2 | 1.69008% | 1.35665% | 1.36646% | $247,074 | $130,432 | $9,501 | $387,007 | 1,750,619,663 | 0.00022 |
| GSLD3/GSLDT3/CS3/CST3 | 0.17376% | 0.13885% | 0.14582% | $25,402 | $13,350 | $1,014 | $39,766 | 187,194,635 | 0.00021 |
| ISST1D | 0.00000% | 0.00000% | 0.00000% | $0 | $0 | $0 | $0 | 0 | 0.00021 |
| ISST1T | 0.00000% | 0.00000% | 0.00000% | $0 | $0 | $0 | $0 | 0 | 0.00022 |
| SST1T | 0.13926% | 0.11056% | 0.25009% | $20,359 | $10,629 | $1,739 | $32,727 | 150,031,028 | 0.00022 |
| SST1D1/SST1D2/SST1D3 | 0.02283% | 0.01632% | 0.02167% | $3,337 | $1,569 | $151 | $5,057 | 23,594,871 | 0.00021 |
| CILC D/CILC G | 3.34641% | 2.54154% | 2.46931% | $489,214 | $244,350 | $17,169 | $750,733 | 3,469,946,584 | 0.00022 |
| CILC T | 1.41334% | 1.03565% | 1.03684% | $206,618 | $99,570 | $7,209 | $313,397 | 1,522,653,717 | 0.00021 |
| MET | 0.09165% | 0.09097% | 0.09781% | $13,398 | $8,746 | $680 | $22,824 | 96,643,843 | 0.00024 |
| OL1/SL1/PL1 | 0.54012% | 0.06695% | 0.70506% | $78,960 | $6,437 | $4,902 | $90,299 | 555,624,734 | 0.00016 |
| SL2 | 0.06822% | 0.04783% | 0.04447% | $9,973 | $4,599 | $309 | $14,881 | 70,174,667 | 0.00021 |
| TOTAL | | | | $14,619,065 | $9,614,230 | $695,304 | $24,928,600 | 103,009,994,000 | 0.00024 |

Note: There are currently no customers taking service on Schedules ISST1(D) or ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 Factor.

(1) From Form 42-6P, Col 11
(2) From Form 42-6P, Col 12
(3) From Form 42-6P, Col 13
(4) Total Energy $ from Form 42-1P, Line 5b x Col 1
(5) Total CP Demand $ from Form 42-1P, Line 5b x Col 2
(6) Total GCP Demand $ from Form 42-1P, Line 5b x Col 3
(7) Col 4 + Col 5 + Col 6
(8) Projected KWH sales for the period January 2005 through December 2005
(9) Col 7 / Col 8 x 100

# FLORIDA POWER & LIGHT COMPANY

## MARTIN UNIT 8
## POWER PLANT SITING APPLICATION
## PA 89-27A

## FINAL ORDER OF CERTIFICATION AND EXCERPTS FROM CONDITIONS OF CERTIFICATION – SECTION IV - AIR

RRL-1
DOCKET NO. 040007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT _____
PAGES 1-38

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI EXHIBIT NO. 5
COMPANY/ F.P.+L.
WITNESS: R.R. LaBauve (RRL-1)
DATE 11-08-04

**STATE OF FLORIDA**
**SITING BOARD**

| | | | |
|---|---|---|---|
| **IN RE:** | **FLORIDA POWER & LIGHT COMPANY MARTIN UNIT 8 POWER PLANT SITING APPLICATION NO. PA89-27A.** | **DOAH CASE NO.** | **02-0573EPP** |
| | | **OGC CASE NO.** | **02-0197** |

## FINAL ORDER OF CERTIFICATION

On March 5, 2003, an administrative law judge with the Division of Administrative Hearings ("DOAH") submitted his Recommended Order on site certification in this administrative proceeding. The Recommended Order indicates that copies were served upon counsel for Florida Power & Light Company ("FPL"), Florida Department of Environmental Protection ("DEP"), Martin County, and upon other designated state and regional agencies. A copy of the Recommended Order is attached as Exhibit A. The matter is now before the Governor and Cabinet, sitting as the "Siting Board," for final action under the Florida Electrical Power Plant Siting Act ("PPSA") embodied in §§ 403.501-403.518, Florida Statutes.

### BACKGROUND

FPL operates several electrical power plants in this state, including its existing Martin Plant located in an unincorporated area in the western portion of Martin County, Florida (the "Martin Site"). The Martin Site encompasses approximately 11,300 acres of property, a portion of which (2,192 acres) has been previously certified under the PPSA. The area surrounding the Martin Site is primarily agricultural and includes croplands, pastures, groves, wetlands, undeveloped lands, and scattered rural residences. The nearest residence is approximately two miles away from the portion of the Martin Site proposed for site certification in this proceeding.

The existing Martin Plant includes two 800 megawatt (nominal) steam-electric generating units known as Units 1 and 2, two 450 megawatt (nominal) combined cycle generating units known as Units 3 and 4, and two 170 megawatt (nominal) simple cycle combustion turbines known as Units 8A and 8B. FPL applied for permits for Martin Units 1 and 2 prior to 1973. Martin Units 1 and 2, which use residual fuel oil and natural gas, began commercial operation in 1980 and 1981, respectively. Martin Units 3 and 4, which use natural gas and are permitted to burn distillate or "light" oil, were certified under the PPSA in 1991 and began operation in 1994.

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Hopping Green Sams & Smith

Units 8A and 8B, which use natural gas and light oil, were approved through modifications of the original site certification in 2000, and began operation in 2001.

On February 1, 2002, FPL filed an application with DEP for site certification with respect to a proposed expansion of the existing Martin Units 8A and 8B ("Unit 8 Project") located at the Martin Site. The Unit 8 Project will utilize approximately 110 acres in the aggregate, all of which acreage is located within the portion of the Martin Site previously certified under the PPSA. However, only approximately 15.5 acres will be occupied by the Unit 8 power block. The Unit 8 Project proposes to combine the two existing combustion turbines (Units 8A and 8B) at the Martin Site, add two new combustion turbines, four heat recovery steam generators (one for each combustion turbine), and one new steam turbine electric generator. The Unit 8 Project also includes two new electrical transmission lines and an optional cooling tower. Natural gas will be the primary fuel for the Unit 8 generating facilities, and light oil will be used as an alternate fuel. When completed and placed in operation, the Unit 8 generating facilities will increase the total installed generating capacity of the Martin Plant by approximately 800 megawatts. The Florida Public Service Commission ("PSC") issued an order on December 10, 2002, determining the need for the Unit 8 Project.

DOAH PROCEEDINGS

DEP forwarded the matter of FPL's requested site certification for the Unit 8 Project to DOAH for formal administrative proceedings, and Administrative Law Judge Charles A. Stampelos ("ALJ") was assigned to the case. In May of 2002, the ALJ conducted a land use hearing in this case as required by the PPSA. The ALJ entered a subsequent Recommended Land Use Order concluding that the site of the Unit 8 Project is consistent and in compliance with the land use plans and zoning ordinances of Martin County. On August 13, 2002, the Siting Board entered an order adopting the ALJ's Recommended Land Use Order and determining that the site of the Unit 8 Project is consistent and in compliance with the land use plans and zoning ordinances of Martin County.

On December 20, 2002, DEP issued its written Staff Analysis Report concerning the Unit 8 Project. DEP's Report contained a compilation of proposed Conditions of Certification for the Unit 8 Project. DEP's Report also included reports from other state, regional, and local agencies. On February 10, 2003, a Joint Prehearing Stipulation was submitted to the ALJ indicating that no party to this administrative proceeding objected to certification of the Unit 8 Project. The parties

joining in the Prehearing Stipulation included FPL, DEP, Martin County, the PSC, the Florida Department of Community Affairs, the Florida Fish and Wildlife Conservation Commission, the Florida Department of Transportation, and the South Florida Water Management District. Pursuant to § 403.508(3), Florida Statutes, the ALJ held a formal administrative hearing on site certification of the Unit 8 Project in Indiantown on February 17, 2003. Expert testimony and other evidence in support of site certification were presented at this hearing by FPL and DEP. Three members of the general public also testified at the certification hearing, but none of them spoke in opposition to the Unit 8 Project.

RECOMMENDED ORDER

On March 5, 2003, the ALJ entered his Recommended Order on site certification of the Unit 8 Project. Included in the Recommended Order, is the ALJ's basic conclusion that FPL met its burden of proof of demonstrating at the certification hearing that the Unit 8 Project, including the proposed transmission line corridor, complies with all the criteria for certification under the PPSA. The ALJ specifically concluded that the unrebutted evidence at the hearing demonstrated that the Unit 8 construction and operation safeguards are sufficient to protect the public welfare. The ALJ further concluded that the Project will result in minimal adverse affects on human health, the environment, the ecology of the land and its wildlife, and the ecology of state waters and their aquatic life. The ALJ ultimately recommended that the Siting Board "grant full and final certification" of the Martin Unit 8 Project.

CONCLUSION

No Exceptions were filed in this administrative proceeding challenging any of the ALJ's findings or conclusions in the Recommended Order on site certification. Furthermore, the record in this proceeding is devoid of objections by any governmental agencies to site certification of the Unit 8 Project. Based on a review of the record and the governing law, the Siting Board concludes that FPL's Unit 8 Project complies with the certification requirements of the PPSA and that site certification of the Project, including the associated transmission line facility, will fully balance the increasing demand for electrical power plant location and operation in this State with the broad interests of the public that are protected by the PPSA.

It is therefore ORDERED that:

A. The following clarifying corrections are made to the Conditions of Certification for the Martin Expansion Project incorporated by reference in the Recommended Order:

1. Condition of Certification I.A. is revised to read as follows:

A. Pursuant to s. 403.501-518, F.S., the Florida Electrical Power Plant Siting Act, this certification is issued to Florida Power and Light Company (FPL) owner/operator of the Martin Power Plant. Under the control of these Conditions of Certification, FPL will operate the Martin Expansion Project consisting of two natural gas-fired Combined Cycle Units No. 3 and No. 4 (each 450 MW nominal), and two simple cycle Units 8A and 8B (each 170 MW nominal) which will be incorporated into Unit 8, a "4 on 1" Combined Cycle Gas Turbine facility (total 1100 MW nominal) and ancillary equipment. The Martin Expansion Project includes future facilities, namely two gas-fired Combined Cycle Units No. 5 and No. 6, and a coal gasification facility; those future facilities will require approval in subsequent proceedings under the Act. These units are located on an 11,300-acre site located in Sections 29 & 30/Township 39 South/Range 37 East in southwestern Martin County.

2. Condition of Certification III.8 is revised to read as follows:

8. "Project" shall mean the Martin Expansion Project and all associated facilities, including: Units 3 and 4, Units 8A and 8B, Combined Cycle Unit 8, coal and limestone handling and related facilities, the cooling pond, gas pipeline, supplemental cooling tower, transmission lines and related facilities. The project consists of four phases. Phase I involved natural gas-fired, combined cycle Units 3 and 4 with distillate fuel oil as backup and an associated natural gas pipeline and transmission line upgrade. Phase II involves incorporation of Units 8A and 8B into combined-cycle Unit 8. Phase III involves Units 5 and 6 fueled by natural gas or onsite coal gasification facilities, with distillate fuel oil and natural gas as backup. Phase IV consists of coal gasification facilities. Phases III and IV will require approval in subsequent proceedings under the Act.

B. The Recommended Order on site certification (Exhibit A) is adopted and incorporated by reference herein.

C. Certification of the location, construction, and continued operation of the Martin Unit 8 Project as described in FPL's site certification application and by the evidence presented at the certification hearing is APPROVED, subject to the Conditions of Certification contained in DEP Exhibit 2, as revised in Paragraph A above.

D. Authority to assure and enforce compliance by FPL and its agents with all of the Conditions of Certification imposed by this Final Order is hereby delegated to DEP, except that

any proposed modification to burn a fuel other than natural gas or light oil shall be reviewed by the Siting Board.

Any party to this proceeding has the right to seek judicial review of the Final Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, M.S. 35, Tallahassee, Florida 32399-3000; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Final Order is filed with the clerk of the Department.

DONE AND ORDERED this 11 day of April, 2003, in Tallahassee, Florida, pursuant to a vote of the Governor and Cabinet, sitting as the Siting Board, at a duly noticed and constituted Cabinet meeting held on April 8, 2003.

THE GOVERNOR AND CABINET
SITTING AS THE SITING BOARD

THE HONORABLE JEB BUSH
GOVERNOR

FILING IS ACKNOWLEDGED ON THIS DATE,
PURSUANT TO § 120.52 FLORIDA STATUTES,
WITH THE DESIGNATED DEPARTMENT CLERK,
RECEIPT OF WHICH IS HEREBY ACKNOWLEDGED

CLERK 4/14/03 DATE

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing Final Order has been sent by United States Postal Service to:

Peter C. Cunningham, Esquire
Douglas S. Roberts, Esquire
Hopping Green & Sams, P.A.
Post Office Box 6526
Tallahassee, FL 32314

Ross Stafford Burnaman, Esquire
Fish and Wildlife Conservation Commission
6230 South Meridian Street
Tallahassee, FL 32399-1600

Robert V. Elias, Esquire
Florida Public Service Commission
Gerald Gunter Building
2450 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Ann Cole, Clerk and
Charles A. Stampelos, Administrative Law Judge
Division of Administrative Hearings
The DeSoto Building
1230 Apalachee Parkway
Tallahassee, FL 32399-1550

Roger Saberson, Esquire
Treasure Coast Regional Planning Council
70 Southeast Fourth Avenue
Delray Beach, FL 33483-4514

Tyson Waters, Esquire
Krista Storey, Esquire
Martin County Attorney's Office
2401 Southeast Monterey Road
Stuart, FL 34996

Colin Roopnarine, Esquire
Department of Community Affairs
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100

Susan Roeder Martin, Esquire
Assistant General Counsel
S. F. Water Management District
Post Office Box 24680
West Palm Beach, FL 33416

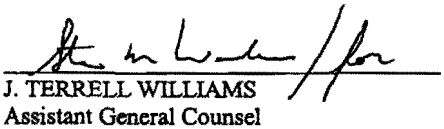
Sheauching Yu, Esquire
Department of Transportation
Haydon Burns Building
605 Suwannee Street
Mail Station 58
Tallahassee, FL 32399-0450

and by hand delivery to:

Scott A. Goorland, Esquire
Department of Environmental Protection
3900 Commonwealth Blvd.
Mail Station 35
Tallahassee, FL 32399-3000

this 14th day of April, 2003.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION



J. TERRELL WILLIAMS
Assistant General Counsel

3900 Commonwealth Blvd., M.S. 35
Tallahassee, FL 32399-3000
Telephone 850/245-2242

**FLORIDA POWER AND LIGHT COMPANY**
**MARTIN EXPANSION PROJECT**
PA 89-27

CONDITIONS OF CERTIFICATION

I. ~~GENERAL~~ CERTIFICATION CONTROL

A. Pursuant to s. 403.501-518, F.S., the Florida Electrical Power Plant Siting Act, this certification is issued to Florida Power and Light Company (FPL) owner/operator of the Martin Power Plant. Under the control of these Conditions of Certification the FPL will operate the Martin Expansion Project including a 1,000 MW (nominal) facility consisting of two natural gas-fired Combined Cycle **Units No. 3 and No. 4**, two simple cycle **Units 8A and 8B** which will be incorporated into **Unit 8** a "4 on 1" Combined Cycle Gas Turbine facility and ancillary equipment. The Martin Expansion Project includes future facilities, given preliminary approval, namely two gas-fired Combined Cycle **Units No. 5 and No.** 6 and potentially a coal gasification facility. These units are located on a 11,300-acre site located in Sections 29&30/Township 39 South/Range 37 East in southwestern Martin County;

B. The general and specific conditions contained in these Conditions of Certification, unless specifically amended or modified, are binding upon the permittee and shall apply to the construction and operation of the certified facility. If a conflict should occur between the design criteria of this project and the Conditions of Certification, the Conditions shall prevail unless amended or modified.

II. APPLICABLE RULES

The construction and operation of the certified facility shall be in accordance with all applicable provisions of Florida Statutes and Department and Water Management District rules, including the following regulations: [South Florida WMD: 40E-2, 40E-3, 40E-4, 40E-6, 40-E20 ] 62-4, 62-17, 62-256, 62-296, 62-297, 62-301, 62-302, 62-531, 62-532, 62-550, 62-555, 62-560, 62-600, 62-601, 62-604, 62-610, 62-620, 62-621, 62-650, 62-699, 62-660, 62-701, and 62-814, Florida Administrative Code (F.A.C.), or their successors as they are renumbered, as these regulations existed on the date of the certification of a specific phase, or as they may become applicable pursuant to subsection 403.511 5(a), F.S.

III. Definitions

Unless otherwise indicated herein, ~~T~~the meaning of the terms used herein shall be governed by the definitions contained in Chapters 403, 378, 373, and 253, Florida Statutes and any regulation adopted pursuant thereto and the statutes and regulations of any agency. In the event of any dispute over the meaning of a term used in these

conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definition contained in any other state or federal statute or regulation or, in the alternative, by the use of the commonly accepted meaning as determined by the Department of Environmental Protection. ~~As used herein~~ In addition, the following words shall have the indicated meanings:

1. "Application" shall mean the Site Certification Applications for the Martin Coal Gasification/Combined Cycle Project, ~~and~~ peaking units 8A and 8B and Combined Cycle Unit 8 as supplemented.

2. "DEP" shall mean the Florida Department of Environmental Protection.

3. "Emergency conditions" shall mean urgent circumstances involving potential adverse consequences to human life or property as a result of weather conditions or other calamity, and necessitating new or replacement operating equipment, gas pipeline, transmission lines, or access facilities.

4. "Feasible" or "practicable" shall mean reasonably achievable considering a balance of land use impacts, environmental impacts, engineering constraints, and costs.

5. "FFWCC" shall mean the Florida Fish and Wildlife Conservation Commission.

6. "Permittee" shall mean Florida Power and Light Company (FPL) as owner and operator of the certified facility.

7. "Power plant" shall mean the electric power generating equipment and appurtenances to be constructed on the certified portion of the Martin site in Martin County, as generally depicted in the Application.

8. "Project" shall mean the Martin Expansion Project and all associated facilities, including: Units 3 and 4, Units 8A and 8B, Combined Cycle Unit 8, coal and limestone handling and related facilities, the cooling pond, gas pipeline, supplemental cooling tower, transmission lines and related facilities. The project consists of four phases. Phase I involved natural gas-fired, combined cycle Units 3 and 4 with distillate fuel oil as backup and an associated natural gas pipeline and transmission line upgrade. Phase II involves combined-cycle Unit 8. Phase III involves Units 5 and 6 fueled by natural gas or onsite coal gasification facilities, with distillate fuel oil and natural gas as backup. Phase IV consists of coal gasification facilities.

9. "SFWMD" shall mean the South Florida Water Management District.

10. "ISO" shall mean International Organization for Standardization, ISO 3977-1978(E) standard conditions for gas turbines = 14.7 psia, 150° C, relative humidity 60%.

11. "Facility" shall mean the certified electrical power generation facility and all associated structures, including but not limited to: combustion turbine generators, heat recovery steam generators, duct burners, steam turbine generators, selective catalytic reduction units, transformers, associated transmission lines, substations, fuel and water storage tanks, natural gas delivery metering station, air and water pollution control equipment, storm water control ponds and facilities, cooling towers, and related structures.

12. "DHR" shall mean the Florida Department of State, Division of Historical Resources.

13. "NPDES permit" shall mean the federal National Pollutant Discharge Permit System permit issued in accordance with the federal Clean Water Act.

14. "PSD permit" shall mean the federal Prevention of Significant Deterioration air emissions permit issued in accordance with the federal Clean Air Act.

15. "Title V permit" shall mean the federal permit issued in accordance with Title V of the federal Clean Air Act.

16. "The SE District Office" shall mean the Department's Southeast District Office located at 400 North Congress Avenue, West Palm Beach, FL 33401, (561) 681-6600.

~~A. Applicable Rules~~

~~The construction and operation of the Martin CG/CC Project shall be in accordance with all applicable provisions of at least the following regulations of DEP: Chapters 62-4, 62-17, 62-256, 62-296, 62-297, 62-301, 62-302, 62-531, 62-532, 62-550, 62-555, 62-560, 62-600, 62-601, 62-604, 62-610, 62-620, 62-621, 62-650, 62-660, 62-701, 62-762, 62-767, 62-769, 62-770, 62-814, 62-699, and 62-25, Florida Administrative Code (F.A.C.) or their successors as they are renumbered.~~

~~II~~ IV. AIR

The construction and operation of Martin Expansion Project shall be in accordance with all applicable provisions of Chapters 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. In addition to the foregoing, the project shall comply with the General Requirements, Testing Requirements, Records and Reports requirements of PSD Permits PSD-FL-286 and FL 327, as may be subsequently modified, and the following conditions of certification as indicated. (The following emission limitations and conditions in paragraph ~~II~~ IV.A. reflect final BACT determinations, as determined by the Department under the PSD review, for Units 3 and 4 and preliminary determinations for Units 5 and 6; paragraph ~~II~~ IV.B. are for simple cycle units 8A and 8B; and Paragraph ~~II~~ IV.C. is for Unit 8 in the combined cycle mode firing natural gas and oil. However, emission limitations in this certification do not establish BACT. Emission limitations and conditions concerning phases III and IV of the project were preliminary based on information furnished by the Permittee in order to support certification of ultimate site capacity and shall be determined finally upon review of supplemental applications.)

**A. Emission Limitations for Martin CG/CC Project** - Units 3 and 4

1. The maximum heat input to each CT shall neither exceed 1,966 MMBtu/hr while firing natural gas, nor 1,846 MMBtu/hr while firing fuel oil (@ 40°F). For coal derived gas firing the maximum heat input to each CT shall not exceed 2,100 MMBtu/hr (@ 75°F). These heat input limitations are subject to change. Any changes shall be provided at least 90 days before commercial operation for each fuel available to the site which a unit is capable of firing, at which time this condition may be modified, after proper notice, to reflect those parameters. Each combined cycle unit's fuel consumption shall be continuously determined and recorded.

2. Each of the eight combustion turbines (CTs) may operate continuously, i.e., 8,760 hrs/year.

3. Only natural gas, light distillate fuel oil, or coal derived gas shall be fired in the combustion turbines.

4. The maximum allowable emissions from each CT in accordance with the BACT determination, shall not exceed the following, at 40°F (except during periods of startup and shutdown and except as provided in Condition # IV.A.22.):

Emission Limitations[d]

| Pollutant | Fuel | Basis | Units 3 & 4 | | Units 5 & 6 | |
|---|---|---|---|---|---|---|
| | | | lb/hr/CT | TPY[a] | Lb/hr/CT | TPY[a] |
| NOx | Gas | 25 ppmvd @ 15% $O_2$ | 177 | comb. tot. 3108 | 177 | comb. tot. 3108 |
| | Oil | 65 ppmvd @ 15% $O_2$ | 461 | | 461 | |
| | CG | 42 ppmvd @ 15% $O_2$ | 392 | 6868 | 392 | 6868 |
| VOC[b] | Gas | 1.6 ppmvd | 3 | comb. tot. 57 | 3 | comb. tot. 57 |
| | Oil | 6 ppmvd | 11 | | 11 | |
| | CG | 9 ppmvd | 21.4 | 375 | 21.4 | 375 |
| CO | Gas | 30 ppmvd | 94.3 | comb. tot. 871 | 94.3 | comb. tot. 871 |
| | Oil | 33 ppmvd | 105.8 | | 105.8 | |
| | CG | 33 ppmvd | 134 | 2311 | 134 | 2311 |
| PM/$PM_{10}$ | Gas | | 18 | comb. tot. 100 | 18 | comb. tot. 100 |
| | Oil | | 60.6 | | 60.6 | |
| | CG | | 19 | 333 | 19 | 333 |
| Pb | Gas | | neg. | comb. tot. 0.015 | neg. | comb. tot. 0.015 |
| | Oil | | 0.015 | | 0.015 | |
| | CG | | 0.3 | 5.3 | 0.3 | 5.3 |
| $SO_2$ | Gas | | 91.5 | comb. tot. 568 | 91.5 | comb. tot. 568 |
| | Oil | | 920 | | 920 | |
| | CG | | 834 | 14612 | 834 | 14612 |

a. Tons per year (TPY) emission limits listed for natural gas and oil combined apply as an emission cap based on limiting oil firing to an annual aggregate of 2,000 hours for the 4 CTs, with compliance to be demonstrated in annual operation reports.

b. Exclusive of background concentrations.

c. Sulfur dioxide emissions based on a maximum of 0.5 percent sulfur in oil for hourly emissions and an average sulfur content of 0.3 percent for annual emissions.

d. These limitations for Units 5 and 6 and coal gasification shall not be binding for subsequent BACT determinations.

e. The excess emissions authorized under Rule 17-210.700(1), F.A.C., shall be extended an additional two hours (for a total not to exceed four hours) for a cold turbine start for the first CT of a CC unit. The second CT of each CC unit shall comply with Rule 17-210.700(1), F.A.C.

5. The following emissions~~, determined by BACT,~~ are tabulated for PSD and inventory purposes:

Maximum Allowable Emissions (@ 40°F)

| Pollutant | Fuel | Units 3 & 4 | | Units 5 & 6 | |
|---|---|---|---|---|---|
| | | lb/hr/CT | TPY[a] | lb/hr/CT | TPY[a] |
| $H_2SO_4$[b] Acid Mist | Gas | 11.2 | Comb. tot. 70 | 11.2 | comb. tot. 70 |
| | Oil | 113 | | 113 | |
| | CG | 102 | 1787 | 102 | 1787 |
| Mercury | Gas | 0.021 | Comb. tot. 0.34 | 0.021 | comb. tot. 0.34 |
| | Oil | 0.0052 | | 0.0052 | |
| | CG | 0.024 | 0.42 | 0.024 | 0.42 |
| Fluoride | Oil | 0.055 | 0.055 | 0.055 | 0.055 |
| Beryllium | Oil | 0.004 | 0.004 | 0.004 | 0.004 |

a. Tons per year (TPY) emission limits listed for natural gas and oil combined apply as an emission cap based on limiting oil firing to an annual aggregate of 2,000 hours for the 4 CTs, with compliance to be demonstrated in annual operation reports.

b. Sulfuric acid mist emissions assume a maximum of 0.5 percent sulfur in fuel oil for hourly emissions and an average sulfur content of 0.3 percent for annual emissions.

6. The maximum allowable emissions from each gasifier incinerator stack shall not exceed the following at 75° F:

| Pollutant | Lb/hr/Stack | TPY/Stack | 4 Stacks |
|---|---|---|---|
| Nox | 61 | 268 | 1069 |
| VOC | Negl. | Negl. | Negl. |
| CO | Negl. | Negl. | Negl. |
| $PM/PM_{10}$ | Negl. | Negl. | Negl. |
| $SO_2$ | 32 | 140.2 | 555 |
| Beryllium | 0.0005 | 0.002 | 0.008 |
| Mercury | 0.008 | 0.035 | 0.140 |
| Lead | 0.05 | 0.22 | 0.88 |

7. Auxiliary Steam Boilers and Diesel Generators shall operate only during start-up and shut down, periodic maintenance testing, and for emergency power generation, respectively. NOx emissions for the auxiliary steam boilers shall not exceed

0.3 lb/MMBtu for natural gas firing or for oil firing. NOx emissions for the diesel generators shall not exceed 15.0 grams/hp-hr. Sulfur dioxide emissions limitations for the auxiliary steam boilers and diesel generators are established by firing natural gas or limiting the light distillate fuel oil's sulfur content to 0.3% on an annual basis.

8. Visible emissions shall neither exceed 10% opacity while burning natural gas or coal derived gas, nor 20% opacity while burning distillate oil.

9. Nitrogen oxide emissions from each gas turbine/heat recovery steam generator unit shall be controlled by using dry low NOx combustors for natural gas with steam injection for fuel oil firing. The Permittee shall install duct module(s) suitable for future installation of SCR equipment on each combined cycle generating unit.

10. Initial (I) compliance tests shall be performed on each Combustion Turbine using both fuels. The stack test for each turbine shall be performed within 10% of the maximum heat rate input for the tested operating temperature. Annual (A) compliance tests shall be performed on each Combustion Turbine with the fuel(s) used for more than 400 hours in the preceding 12 month period. Tests shall be conducted using EPA reference methods in accordance with the November 2, 1989, version of 40 CFR 60 Appendix A:

a. 5 or 17 for PM (I, A, for oil only)
b. 8 for sulfuric acid mist (I, for oil only)
c. 9 for VE (I, A)
d. 10 for CO (I, A)
e. 20 for NOx (I, A)
f. 18 for VOC (I, A)
g. Trace elements of Lead (Pb) and Beryllium (Be) shall be tested (I for oil only) using EMTIC Interim Test Method. As an alternative, Method 104 for Beryllium (Be) may be used; or Be and Pb may be determined from fuel analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.
h. ASTM D 2880-71 (or equivalent) for sulfur content of distillate oil (I, A)
i. ASTM D 1072-80, D 3031-81, D 4084-82 or D 3246-81 (or equivalent) for sulfur content of natural gas (I, and A if deemed necessary by DEP)
j. Mercury (Hg) shall be tested using EPA Method 101 (40 CFR 61, Appendix B) (I)

Other DEP approved methods may be used for compliance testing after prior Departmental approval.

11. The average annual sulfur content of the light distillate fuel oil shall not exceed 0.3% by weight. The maximum sulfur content of the light distillate fuel oil shall not exceed 0.5%. Compliance shall be demonstrated in accordance with the requirements of 40 CFI 60.334 by testing for sulfur content of oil storage tanks once per day when firing oil using ASTM D 2880-71, testing for nitrogen content, and testing for heating value.

12. Continuous emission monitoring shall be installed, operated, and maintained in accordance with 40 CFR 60, Appendix F, for each combined cycle unit to monitor nitrogen oxides.

a. Each continuous emission monitoring system (CEMS) shall meet performance specifications of 40 CFR 60, Appendix B.

b. CEMS data shall be recorded and reported in accordance with Chapter 17 2, F.A.C., and 40 CFR 60. The record shall include periods of startup, shutdown and malfunction.

c. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

d. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation and operation of all CEMS.

e. For purposes of reports required under this certification, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Condition # IV.A.18 herein, which exceeds the applicable emission limits in Condition # IV.A.4.

13. To determine compliance with the oil firing heat input limitation, the Permittee shall maintain daily records of fuel oil consumption and hourly usage for each turbine and heating value for such fuel. All records shall be maintained for a minimum of three years after the date of each record and shall be made available to representatives of the Department upon request.

14. The source shall be in compliance with all requirements of 40 CFR 60 Subpart GG, (Standards of Performance for Stationary Gas Turbines) and Rule 62-204.800(7), F.A.C. (Standard of Performance for New Stationary Sources (NSPS)).

a. Natural Gas

Pursuant to 40 CFR 60.334(b)(2), a custom fuel monitoring schedule shall be followed for the natural gas fired at this facility and shall be as follows:

Custom Fuel Monitoring Schedule for Natural Gas

i. Monitoring of fuel nitrogen content shall not be required if NG is the only fuel being fired in the turbines.

ii. Sulfur Monitoring

(a.) Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are ASTM D1072-80, ASTM D3031-81, ASTM D3246-81, and ASTM D4084-82 as referenced in 40 CFR 60.335, or the latest edition(s).

(b) This custom fuel monitoring schedule shall become effective on October 14, 1997. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates continuous compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters. If monitoring data is provided by the applicant which demonstrates consistent compliance with the requirements herein, the applicant may begin monitoring as per the requirements of ii(c).

(c) If after the monitoring required in item ii(b) above, or herein, the sulfur content of the fuel shows little variability and calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

(d) Should any sulfur analysis as required in items ii(b) or ii(c) above indicate noncompliance with 40 CFR 60.333, the owner or operator shall notify the Department of such excess emissions and the custom schedule shall be re-examined. ~~by the Environmental Protection Agency.~~ Sulfur monitoring shall be conducted weekly during the interim period when this schedule is being re-examined.

iii. If there is a change in the fuel supply, the owner or operator must notify the Department of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered as a change in the fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

iv. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of five years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.

b. New No. 2 Fuel Oil

The records of new No. 2 fuel oil usage shall be kept by the company for a five year period for regulatory inspection purposes. For sulfur dioxide, periods of excess emissions shall be reported if the fuel oil being fired in the gas turbine exceeds 0.5 percent sulfur content and 0.3 percent sulfur content, by weight, for hourly and annual emissions, respectively.

15. Any change in the method of operation, fuels, or equipment, shall be submitted for approval to DEP's Bureau of Air Regulation.

16. The Permittee shall have required sampling tests of the emissions performed within 60 days after achieving the maximum turbine firing rate, but not later than 180 days from the start of operation. Thirty (30) days notice prior to the initial sampling test and fifteen (15) days notice before subsequent annual testing shall be provided to the Southeast District Office. Written reports of the tests shall be submitted to the Southeast District Office within 45 days of test completion.

17. If construction does not commence on Phase I within 18 months of issuance of this certification/permit, then the Permittee shall obtain from DEP a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 5.2l(r)(2)). Units to be constructed or modified in later phases of the project will be reviewed and limitations revisited under the supplementary review process of the Power Plant Siting Act.

18. Quarterly excess emission reports, in accordance with the November 2, 1989, version 40 CFR 60.7(c) and 60.334(c) shall be submitted to DEP's Southeast District office. Annual reports shall be submitted to the District Office in accordance with Rule 62-210.370(3)(c), F.A.C.

19. Literature of equipment selected shall be submitted as it becomes available. A CT-specific graph of ambient temperature and heat inputs to the CT shall be submitted to DEP's Southeast District Office and the Bureau of Air Regulation.

20. Stack sampling facilities shall be provided for each of the CT and incinerator stacks.

21. Construction period fugitive dust emissions shall be minimized by covering or watering dust generation areas.

22. FPL may alter the DIM II combustors for the four CTs subject to these conditions, operate the CT receiving the first altered DIM II combustor for a maximum period of 60 days for adjustment; and, operate each of the other three CTs for a maximum period of 30 days, after installation of the altered DIM II combustors, for adjustment provided the following conditions are met:

a. The Department's Southeast District Air Program Administrator shall be notified in writing a minimum of 10 days in advance of initially placing any altered DIM II combustor into service.

b. To allow time for evaluation and testing of alterations to the dry low NOx combustor (DIM) design, the emission limitations in Specific Condition 4 of the referenced permit shall not apply a sixty (60) day period following installation of the final DIM design configuration in the initial CT and shall not apply during a thirty (30) day period per CT following installation of the final DIM design in each of the remaining three CTs. During the evaluation and testing of the altered combustors, the maximum nitrogen oxides (NOx) emissions shall comply with the emission limit specified by the new source performance standards for CT, 40 CFR 60, Subpart GG. The annual allowable emissions (TPY) of NOx for each CT in permit PSD-FL-146 and these conditions shall not be exceeded.

c. Except during CT performance testing for extreme conditions, carbon monoxide (CO) emissions shall not exceed 100 ppmvd. The maximum CO emissions during a 12 hour test period to evaluate CT performance during extreme conditions shall not exceed 500 ppmvd, 30 minute average. The annual allowable emissions (TPY) of CO for each CT in permit PSD-FL-146 and these conditions shall not be exceeded.

d. The volatile organic compound (VOC) emissions shall not exceed 20 ppmvd except during CT performance testing for extreme conditions. During the 12 hour test period to evaluate CT performance during extreme conditions, VOC emissions shall not exceed 100 ppmvd. The annual allowable emissions (TPY) of VOC from each CT in permit PSD-FL-146 and these conditions shall not be exceeded. The VOC emissions shall be evaluated during the testing periods by measuring total unburned hydrocarbons (UHC). FPL shall determine the VOC component of UHC emissions at several different UHC levels during the testing of the first combustion turbine to have the new DIM II combustors installed. The ratio of VOC/UHC concentration shall be measured, as a minimum, at the low, medium, and high UHC concentration observed during the CT performance tests. The VOC component of the UHC emissions shall be attributed against the annual 57 ton VOC emission limit for the facility. The UHC levels shall not exceed 40 ppmvd during the test period. However,

during the 12-hour non-continuous CT performance testing for extreme conditions, UHC emissions shall not exceed 500 ppmvd.

e. After the adjustment period, each CT must be in compliance with all limitations in the condition ~~II~~ IV.A.4.

f. Within 45 days after the completion of the project, the permittee shall furnish the Department with a report summarizing the variation in parameters and emissions of NOx, VOC, and CO from the modified DIM II on all of the CTs and any operation problems with the CT units remaining to be resolved.

**B. Emissions and Controls for CTs 8A and 8B** [Emissions Units 011 and 012] In simple Cycle Mode.

The following conditions in this section apply in accordance with PSD permit No. PSD-FL-286 until commencement of steam blows on Unit 8 "4 on1" Combined Cycle per PSD Permit No. PSD-FL-327.

1. NSPS Requirements: Each combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

2. Combustion Turbines: The permittee is authorized to install, tune, operate and maintain two new General Electric Model PG7241(FA) combustion turbines [Emission Units 011 and 012] with electrical generator sets, each designed to produce a nominal 170 MW of electrical power.

3. Permitted Capacity: The heat input rates (HHV) to each combustion turbine shall not exceed the following: Normal Gas Firing:

(a) 1860 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 182 MW.

(b) Gas Firing With Power Augmentation (Steam Injection): 1800 mmBTU per hour of natural gas with a compressor inlet air temperature of 59° F and producing a maximum 180 MW.

(c) Gas Firing With Peaking: 1920 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 190 MW.

(d) Distillate Oil Firing: 2008 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 191 MW.

The heat input rates are based on the higher heating values (HHV) of 23,127 BTU/lbm for natural gas and 19,490 BTU/lbm for distillate oil. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Compliance shall be determined by data compiled from the automated gas turbine control system. This data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]

4. Simple Cycle Operation Only: Each combustion turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the basis of the CO and NOx BACT determinations in the PSD and resulted in the emission standards specified in ~~this permit~~ these Conditions of Certification.

Specifically, the CO and NOx BACT determinations in the PSD eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to operation as peaking units. Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be accompanied by a revised CO and NOx BACT analysis and the approval of the Department through a permit modification in accordance with Chapters 62-210 and 62-212, F.A.C. Note: The results of this analysis may validate the initial BACT determinations or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards. [Applicant Request; Rules 62-210.300 and 62-212.400, F.A.C.]

5. Allowable Fuels: Each combustion turbine shall be designed and tuned for a primary fuel of pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, each combustion turbine may be fired with low sulfur No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. No other fuels are authorized by ~~this permit~~ these Conditions of Certification. It is noted that both limitations are much more stringent than the sulfur dioxide limitation in 40 CFR 60, NSPS Subpart GG and assures compliance with regulations 40 CFR 60.333 and 60.334 of this subpart. The permittee shall demonstrate compliance with the fuel sulfur limits by keeping the records specified in ~~this permit~~ these Conditions. [Application; Rule 62-210.200(PTE), F.A.C.]

6. Alternate Gas Firing Methods of Operation

(a) Power Augmentation Mode: In accordance with the manufacturer's recommendations, steam may be injected into each combustion turbine when firing natural gas to provide additional peaking power during periods of high electrical power demand. Each unit shall not exceed 400 hours of power augmentation during any consecutive 12 months. To qualify as "power augmentation mode", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. Power augmentation when firing distillate oil is prohibited.

(b) High Temperature Peaking Mode: In accordance with the manufacturer's recommendations, each combustion turbine may be operated in a high temperature peaking mode when firing natural gas to provide additional power during periods of peak electrical power demands. Peaking is achieved through the automated gas turbine control system by allowing slightly higher exhaust temperatures, calculating a new combustion reference temperature for the peak load, and adjusting the fuel distribution between the fuel nozzles to maintain lean pre-mix firing. During the transfer from base load to peak load and during peak load operation, each unit will remain in the per-mix steady state mode. Each unit shall not exceed 60 hours of peaking during any consecutive 12 months. To qualify as "peaking mode", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the peaking mode, the operator shall log the date, time, and new mode of operation. Peaking when firing distillate oil is prohibited.

Rules 62-4.070(3) and 62-212.400, F.A.C. (BACT)]

7. Restricted Operation

(a) Gas Firing: Each combustion turbine shall fire no more than 5,902,588,000 standard cubic feet of natural gas during any consecutive 12 months (equivalent to 3390 hours per year at the maximum firing rate for a compressor inlet air temperature of 59° F).

(b) Oil Firing: Each combustion turbine shall fire no more than 7,358,350 gallons of distillate oil during any consecutive 12 months (equivalent to 500 hours per year at the maximum firing rate for a compressor inlet temperature of 59° F). If oil is fired, the natural gas consumption limit shall be reduced by 118 standard cubic feet of gas for every gallon of distillate oil fired.

The permittee shall install, calibrate, operate and maintain a monitoring system for each combustion turbine to measure and accumulate the quantity of fuel and hours of operation for each method of operation. [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

8. Operating Procedures: ~~The Best Available Control Technology (BACT) determinations established by this permit rely on.~~ In order to insure that "good operating practices" are used to minimize emissions~~. Therefore~~, all operators and supervisors shall be properly trained to operate and maintain the combustion turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

9. Automated Control System: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ automated gas turbine control system for each unit. Each system shall be designed and operated to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: air/fuel distribution and staging, turbine speed, load conditions, exhaust temperatures, heat input, and fully automated startup and shutdown. [Design; 62-212.400(BACT), F.A.C.]

10. DLN Combustion Technology: In accordance with the manufacturer's recommendations, the permittee shall install, tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to control NOx emissions from each gas turbine. [Design; Rule 62-212.400(BACT), F.A.C.]

11. Tuning: Prior to the initial emissions performance tests for each gas turbine, the DLN 2.6 combustors and automated gas turbine control systems shall be tuned to optimize the reduction of CO, NOx, and VOC emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations to minimize these pollutant emissions. During tuning sessions, each combustion turbine shall be tuned for CO and NOx emissions performance of 9.0 ppmvd corrected to 15% oxygen or better. The permittee shall provide at least 5 days advance notice prior to any tuning session. [Design; Rule 62-212.400(BACT), F.A.C.]

12. Carbon Monoxide (CO)

a. *Gas Firing, Normal:* When firing natural gas under normal operating conditions, CO emissions from each combustion turbine shall not exceed 32.0

pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

b. *Gas Firing With Power Augmentation:* When firing natural gas and injecting steam to provide power augmentation, CO emissions from each combustion turbine shall not exceed 47.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load or higher.

c. *Distillate Oil Firing:* When firing low sulfur distillate oil as a backup fuel, CO emissions from each combustion turbine shall not exceed 68.0 pounds per hour and 20.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

The permittee shall demonstrate compliance with these standards by conducting performance tests in accordance with EPA Method 10 and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]

13. Nitrogen Oxides (NOx)

a. *Gas Firing, Normal*: When firing natural gas under normal operating conditions, NOx emissions from each combustion turbine shall not exceed 66.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 10.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor.

b. *Gas Firing With Power Augmentation*: When firing natural gas and injecting steam to provide power augmentation, NOx emissions from each combustion turbine shall not exceed 82.0 pounds per hour and 12.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load or higher. In addition, NOx emissions shall not exceed 12.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor.

c. *Gas Firing With Peaking*: When firing natural gas with high temperature peaking, NOx emissions from each combustion turbine shall not exceed 105.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load. In addition, NOx emissions shall not exceed 15.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

d. *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, NOx emissions from each combustion turbine shall not exceed 334.0 pounds per hour and 42.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 42.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor.

NOx emissions are defined as oxides of nitrogen measured as $NO_2$. The permittee shall demonstrate compliance by conducting performance tests and emissions monitoring in accordance with EPA Methods 7E, 20, and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.332]

14. Particulate Matter (PM/PM10) and Sulfur Dioxide ($SO_2$)

a. *Particulate Matter*: When firing natural gas under any method of operation, particulate matter emissions from each combustion turbine shall not exceed 9.0 pounds per hour based on a 3-hour test average conducted at base load. When firing distillate oil, particulate matter emissions from each combustion turbine shall not exceed 17.0 pounds per hour based on a 3-hour test average conducted at base load

b. *Fuel Specifications.* Emissions of PM, $PM_{10}$, and $SO_2$ shall be limited by the use of pipeline-quality natural gas containing no more than 1 grain per 100 standard cubic feet as the primary fuel and restricted use of No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight as a backup fuel. The fuel specifications are work practice standards ~~established as~~ which were determined by the Department under its PSD review to be BACT limits for PM, $PM_{10}$, and $SO_2$ emissions. The permittee shall demonstrate compliance with the fuel sulfur limits by maintaining the records specified in this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.333]

c. *VE Standard.* When firing natural gas or distillate oil, visible emissions from each combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The visible emissions limits are work practice standards established as BACT limits for PM and PM10 emissions. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]

15. Volatile Organic Compounds (VOC)

a. *Gas Firing With or Without Power Augmentation*: When firing natural gas, VOC emissions shall not exceed 3.0 pounds per hour and 1.5 ppmvw based on a 3-hour test average conducted at base load.

b. *Distillate Oil Firing*: When firing distillate oil, VOC emissions shall not exceed 7.5 pounds per hour and 3.5 ppmvw based on a 3-hour test average conducted at base load.

The VOC standards are established as PSD-synthetic minor limits. VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Methods 25, 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Design; Rule 62-4.070(3), F.A.C.]

16. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, power augmentation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

17. Excess Emissions Allowed: For each combustion turbine, excess NOx and visible emissions during startup, shutdown, and documented malfunction shall be allowed, providing:

a. Operators employ best operational practices to minimize the amount and duration of excess emissions.

b. Operation below 50% of base load shall not exceed 120 minutes during any calendar day.

c. During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to ten, 6-minute observation periods during any calendar day. Data for each observation period shall be exclusive for the ten periods.

d. During all startups, shutdowns, and malfunctions, the NOx CEM shall monitor and record NOx emissions. For each calendar day, up to two 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each combustion turbine due to excess NOx emissions resulting from startup, shutdown, and documented malfunction. For excess NOx emissions due to malfunction, the permittee shall notify the ~~SE District Office~~ Southeast District Office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

e. If the permittee provides at least 5 days advance notice prior to tuning in accordance with the manufacturer's recommendations, up to three 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each gas turbine due to excess NOx emissions resulting from tuning. Note: It is expected that no more than two tuning sessions would occur each year. [Design; Rule 62-210.700(1) and (5); rule 62-4.130, F.A.C.]

18. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

19. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

20. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify the ~~SE District Office~~ Southeast District Office as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

**C. Emissions and Controls for Unit 8 - "4 on 1" Combined Cycle Gas Turbine** [Emission Units 011, 012, 017 and 018]

1. NSPS Requirements: The Department determines that compliance with the ~~BACT~~ emissions performance and monitoring requirements included in these Conditions of Certification also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60.

~~For completeness, the applicable requirements of Subparts Da and GG are included in Appendices Da and GG of this permit.~~ [Rule 62-204.800(7), F.A.C.]

2. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain four new General Electric Model PG7241FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include the Speedtronic™ automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system, an evaporative inlet air-cooling system, and a bypass stack for simple cycle operation. The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. Gas-fired fuel heaters will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. *{Permitting Note: Two existing simple cycle General Electric Model PG7241FA gas turbine-electrical generator sets, Units 8A and 8B (EU 011 and 012), will be incorporated into the "4-on-1" combined cycle Unit 8.}*

3. Gas Turbine NOx Controls

a. *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the simple cycle permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

b. Water Injection: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. The automated control system shall be programmed to establish a water-to-fuel ratio designed to achieve the NOx emission standard for simple cycle oil firing on a 1-hour basis.

c. (SCR) System: The permittee shall install, tune, operate, and maintain a selective catalytic reduction (SCR) system to control NOx emissions from each gas turbine during combined cycle operation when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip.

[Design: Rule 62-212.400(BACT), F.A.C.]

4. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs) with separate HRSG exhaust

stacks. Each HRSG shall be designed to recover heat energy from one of the four gas turbines (8A-8D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NOx/MMBtu.

5. Permitted Capacity-Combustion Turbines: The maximum heat input rate to each gas turbine is 1600 MMBtu per hour when firing natural gas and 1811 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

6. Permitted Capacity - HRSG Duct Burners: The total heat input rate to the duct burners for each HRSG is 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

7. Methods of Operation: Subject to the restrictions and requirements of this ~~permit~~ certification, the gas turbines may operate under the following methods of operation.

a. *Hours of Operation*: Subject to the operational restrictions of this ~~permit~~ certification, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.

b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Each gas turbine shall fire no more than 500 hours of distillate oil during any consecutive 12 months.

c. *Simple Cycle Operation*: Each gas turbine may operate individually in simple cycle mode to produce only direct, shaft-driven electrical power subject to the following operational restrictions.

(1) Each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.

(2) After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple

cycle mode for no more than an average of 1000 hours per gas turbine during any consecutive 12 months.

d. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and deliver steam to the steam turbine-electrical generator to produce steam-generated electrical power as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

e. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging" and may be used in either simple cycle or combined cycle modes.

f. *Peaking*: When firing natural gas, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. During any consecutive 12 months, each gas turbine shall operate while in the peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation.

g. *Power Augmentation*: When firing natural gas in either simple cycle or combined cycle modes, steam may be injected into each gas turbine to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. Total combined operation of power augmentation and peaking modes shall not exceed 400 hours per unit during any consecutive 12 months.

h. *Combined Cycle Operation with Duct Firing*: When firing natural gas and operating in combined cycle mode, each HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input rate to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

8. Emissions Standards: Emissions from each gas turbine shall not exceed the following standards.

| Pollutant | Fuel | Method of Operation | Stack Test, 3-Run Average | | CEMS Block Average |
|---|---|---|---|---|---|
| | | | Ppmvd @ 15% $O_2$ | lb/hour | Ppmvd @ 15% $O_2$ |
| CO[a] | Oil | Simple or Combined Cycle | 14.4 | 64.7 | 15.0, 24-hr |
| | Gas | Simple Cycle | 7.4 | 27.5 | 8.0, 24-hr |
| | | Simple Cycle w/PA | 12.0 | 45.0 | 12.0, 24-hr |
| | | Combined Cycle, Normal | 7.4 | 27.5 | 10.0, 24-hr |
| | | Combined Cycle, All Modes | NA | NA | |
| Nox[b] | Oil | Simple Cycle | 42.0 | 319.2 | 42.0, 3-hr |
| | | Combined Cycle w/SCR | 10.0 | 76.0 | 10.0, 24-hr |
| | Gas | Simple Cycle | 9.0 | 58.7 | 9.0, 24-hr |
| | | Simple Cycle w/PA | 12.0 | 76.2 | 12.0, 24-hr |
| | | Simple Cycle w/Peaking | 15.0 | 95.3 | 15.0, 24-hr |
| | | Combined Cycle w/SCR, Normal | 2.5 | 16.3 | 2.5, 24-hr |
| | | Combined Cycle w/SCR and DB | 2.5 | 23.6 | |
| | | Combined Cycle w/SCR, All Modes | NA | NA | |
| PM/$PM_{10}$[c] | Oil/Gas | Simple or Combined Cycle | Fuel Specifications | | |
| | | Simple or Combined Cycle | Visible emissions shall not exceed 10% opacity for each 6-minute block average. | | |
| SAM/$SO_2$[d] | Oil/Gas | Simple or Combined Cycle | Fuel Specifications | | |
| VOC[e] | Oil | Simple or Combined Cycle | 2.5 | 6.0 | NA |
| | Gas | Simple or Normal Combined Cycle | 1.3 | 2.8 | NA |
| | | Combined Cycle, w/DB and/or PA | 4.0 | 10.5 | NA |
| Ammonia[f] | Oil/Gas | Combined Cycle w/SCR | 5 | NA | NA |

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hour CO standards shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NOx mass emission rates are defined as oxides of nitrogen expressed as $NO_2$. Compliance with the 24-hour NOx CEMS standards during simple cycle operation shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

c. The fuel specifications established in Condition No. IV.C.0 of this section combined with the efficient combustion design and operation of each gas turbine ~~represents~~ were set using the Department's ~~the~~ Best Available Control

Technology (BACT) determination for PM/PM10 emissions in its PSD review. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications in Condition No. IV.C.8 of this section effectively limit the potential emissions of SAM and SO2 from the gas turbines ~~and represent~~ were set using the Department's Best Available Control Technology (BACT) determination for these pollutants in its PSD review. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. IV.E.6. of this section.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may be also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Subject to the requirements of Condition IV.D.5. of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027. [Rule 62-212.400(BACT), F.A.C.]

9. Combined Cycle Operation With Dump Condenser: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to a condenser. When operating in this manner, each unit shall comply with the standards established for combined cycle operation with ammonia injection (SCR).

10. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. [Subpart Da, 40 CFR 60]

11. Existing Units 8A and 8B Simple Cycle Gas Turbines: Until commencement of the initial steam blows, the terms and conditions in IV.B. above shall apply to the two existing Unit 8 gas turbines, 8A and 8B (Emissions Unit Nos. 011 and 012), the two existing gas-fired fuel heaters (Emissions Unit 013) and the distillate oil storage tank (Emissions Unit 014). Thereafter, the conditions contained in IV.C. shall replace the conditions in IV.B. above. [Rule 62-4.070(3), F.A.C.]

12. Operating Procedures: ~~The Best Available Control Technology (BACT) determinations established by this permit rely on~~ In order to ensure that "good operating practices" will be used to reduce emissions~~. Therefore~~, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices

as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

13. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

14. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

15. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the SE District Office by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases.

a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

b. For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

c. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

d. For oil-to-gas fuel switching in simple cycle operation, excess emissions shall not exceed 1 hour in any 24-hour period.

Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

16. Initial Steam Blows: Prior to completing the conversion from simple cycle to combined cycle operation, the permittee is authorized to operate each gas turbine at loads below 50% for the purpose of cleaning the HRSG piping system and piping connecting the HRSG to the steam turbine. Prior to conducting any steam blows, the permittee shall submit a proposed schedule to the SE District Office. On the first day of conducting steam blows, the permittee shall notify the ~~SE District Office~~ SE District Office that the process has begun. The permittee shall complete this process within 90 days of conducting the initial steam blow. For good cause, the permittee may request that the ~~SE District Office~~ SE District Office extend the steam blow period. During the steam blows, the following conditions apply:

a. The permittee shall take all precautions to minimize the extent and duration of excess emissions.

b. Each gas turbine shall fire only natural gas and each CEMS shall be on line and functioning properly.

c. CO and NOx emissions may exceed the ~~BACT~~ limits specified in this ~~permit~~ certification; however, NOx emissions shall not exceed the NSPS Subpart GG limit of 110 ppmvd corrected to 15% oxygen based on a 24-hour block average. If the NSPS standard is exceeded, the permittee shall notify the SE District Office within 24-hours of the incident.

Within 30 days of completing the initial steam blows, the permittee shall submit a report to the Bureau of Air Regulation and the SE District Office summarizing the daily emissions resulting from each steam blow.

17. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the SE District Office with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

**D. Emissions Performance Testing (Phase II)**

1. Test Methods: Any required tests shall be performed in accordance with the following reference methods:

| Method | Description of Method and Comments |
|---|---|
| CTM-027 | Procedure for Collection and Analysis of Ammonia in Stationary Source<br>{Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.} |
| 7E | Determination of Nitrogen Oxide Emissions from Stationary Sources |
| 9 | Visual Determination of the Opacity of Emissions from Stationary Sources |
| 10 | Determination of Carbon Monoxide Emissions from Stationary Sources<br>{Notes: The method shall be based on a continuous sampling train.} |
| 18 | Measurement of Gaseous Organic Compound Emissions by Gas Chromatography<br>{Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.} |
| 20 | Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines |
| 25A | Determination of Volatile Organic Concentrations |

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

2. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NOx, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated for each unit configuration (i.e., simple cycle and combined cycle operation), but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas and distillate oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial 3-hour CO and NOx standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may also be used to demonstrate compliance with the CO and NOx mass emissions standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after the replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1., F.A.C.]

3. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the SE District Office summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

4. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia slip. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}* [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

5. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

**E. Continuous Monitoring and Reporting Requirements (Phase II)**

1. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NOx from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the SE District Office.

a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the SE District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set

appropriately considering the allowable methods of operation and corresponding emission standards.

b. *NOx Monitors.* Each NOx monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the $NO_X$ monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NOx monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

c. *$O_2$ or $CO_2$ Monitors.* The oxygen (O2) or carbon dioxide (CO2) content of the flue gas shall be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

d. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NOx as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

e. *3-hour Block Averages:* For oil firing during simple cycle operation, the 3-hour block average shall be calculated from three consecutive hourly average emission rate values. For purposes of determining compliance with the CEMS emission standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 3-hour block average shall be determined using the remaining hourly data in the 3-hour block. [Rule 62-212.400(BACT), F.A.C.]

f. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

g. *Data Exclusion*. Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, DLN tuning, and steam blows. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 16 and 18 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

h. *Availability*. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this certification, except as otherwise authorized by the Department's SE District Office.
[ [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

2. Water Injection Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. The NOx CEMS is used to demonstrate compliance with the NOx emissions standards. During NOx monitor downtimes or malfunctions, the permittee shall operate at the water-to-fuel ratio that is consistent with the documented flow rate for the gas turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

3. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

4. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

5. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

6. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this certification by maintaining the following records of the sulfur contents.

a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each SE District Office before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the

certified fuel sulfur analysis from the fuel vendor. At the request of the SE District Office, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

7. Malfunction Notification: Within one working day of a malfunction that causes emissions in excess of a standard, subject to the specified averaging periods), the permittee shall notify the SE District Office. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the ~~SE District Office~~ SE District Office, the permittee shall submit written quarterly reports summarizing the malfunctions. [Rule 62-210.700, F.A.C.]

8. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(d), the permittee shall submit a report to the SE District Office summarizing any emissions in excess of the NSPS standards within 30 days following the end of each calendar quarter. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NOx or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO2 emissions in excess of the NSPS standards except during startup or shutdown. [40 CFR 60.7]

9. Quarterly Permit Excess Emission Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the SE District Office summarizing periods of excess CO and NOx emissions. Such information shall also be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

**F. Four Gas-Fired Fuel Heaters** [Emission Unit IU 013]

1. NSPS Subpart Dc Applicability: The gas-fired fuel heaters are subject to Subpart Dc of the New Source Performance Standards in 40 CFR 60 as well as the General Provisions of Subpart A. This regulation applies to each steam-generating unit with a heat input rate of less than 100 MMBtu per hour, but more than 10 MMBtu per hour. Steam generating unit is defined as, "... a device that combusts any fuel and produces steam or heats water or any other heat transfer medium." [40 CFR 60.40c; 40 CFR 60.41c; Rule 62-204.800(7)(b), F.A.C.]

2. Equipment: The permittee is authorized to install, operate, and maintain four fuel heaters fired exclusively with natural gas at a maximum heat input rate of 24 MMBtu per hour. The fuel heaters will be designed to preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. *{Permitting Note: In accordance with Air Permit No. PSD-FL-286, construction of two gas-fired fuel heaters has been completed.}* [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

3. Hours of Operation: The hours of operation for the gas-fired fuel heaters are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

4. Good Combustion: If visible emissions are greater than 5% opacity, the permittee shall investigate the cause, take appropriate corrective actions, and document the incident. This condition does not impose any initial or periodic testing. [Rules 62-4.070(3) and 62-210.700(4), F.A.C.; 40 CFR 60, Appendix A]

5. Subpart Dc Notification, Reporting and Record Keeping Requirements: The gas-fired fuel heaters are subject to the following notification, reporting and record keeping requirements of 40 CFR 60.48c.

a. The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

2) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

b. The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the SE District Office and shall be postmarked by the 30th day following the end of the reporting period. [40 CFR 60.48c (a), (g), (i), and (j)]

**G. Cooling Tower** [Emission Unit 020]

1. Cooling Tower: The permittee is authorized to install one new 18-cell mechanical draft cooling tower with the following design characteristics: a circulating water flow rate of 310,000 gpm; design hot/cold water temperatures of 104° F/90° F; a design air flow rate of 1,386,055 per cell; a liquid-to-gas air flow ratio of 1.4; and drift eliminators with a drift rate of no more than 0.001 percent. The permittee shall submit the final design details within 60 days of selecting the vendor.

2. Drift Rate: Within 60 days of commencing operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of

no more than 0.001 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

H. Materials Handling and Storage (Phases III and IV)

1. The materials handling and storage operations may be continuous, i.e. 8,760 hrs/yr.

2. The material handling/usage rates shall not exceed the following:

Handling/Usage Rate

| Material | TPY |
|---|---|
| Coal | 6,935,000 |
| Slag and Fly Slag | 1,700,000 |
| Sulfur | 310,000 |
| Spent Solvent | 80 |
| Spent Claus Catalyst | 80 |
| Demineralizer Resin Beds | 70 |

3. The maximum particulate matter emissions from the material handling and storage activities shall not exceed 1,566 tons per year. Emissions from these sources shall be controlled using the following measures:

| Fugitive Dust Source | Control Technology |
|---|---|
| Coal Unloading | Enclosed with Dry Collection System |
| Limestone Unloading | Wet Suppression System[1] |
| Conveyors and Transfer Points (Coal, Limestone, Slag) | Transfer Points Enclosed with Dry Collection System Conveyors Covered. |
| Coal Storage (Inactive) | Crusting Agent Application (60% Control) |
| Coal Storage (Active) | Surfactant Application[1] |
| Coal Storage (Active) and Reclaiming | Surfactant Application |
| Limestone Storage | Crusting Agent Application[1] |
| Slag Transport to By Product Storage Area | Paved Road, Covered Conveyor (95% Control) |
| Slag By Product Storage Area (Inactive) | Topsoil Covered and Seeded (100% Control) |
| Slag By Product Storage Area (Active) | Compaction, Temporary Cover (Natural or Synthetic) |
| Sulfur Storage | Stored in molten state in tanks or in crystalline slab arrangement. |

1 Undefined rate of fugitive dust control.

The emissions from the above listed sources where baghouses are used are subject to the particulate emission limitation requirements of 0.03 gr/dscf. However, DEP will not require particulate tests in accordance with EPA Method 5 unless the VE limit of 5% opacity is exceeded for a given source, or unless DEP, based on other information, has reason to believe the particulate emission limits are being violated.

4. Visible Emissions (VE) shall not exceed 5% opacity from any source in the material handling and treatment area, in accordance with Chapter 62-210, F.A.C.

5. Initial and annual Visible Emission compliance tests for all the emission points in the material handling and treatment area, including, but not limited to, the sources specified in this permit, shall be conducted in accordance with the November 2, 1989, version of 40 CFR 60, using EPA Method 9 or DEP approved method.

6. Compliance test reports shall be submitted to DEP within 45 days of test completion in accordance with Chapter 62-297.310(8), F.A.C.

7. Any changes in the method of operation, raw materials processed, equipment, or operating hours or any other changes pursuant to Rule 17-2.100, F.A.C., defining modification, shall be submitted for approval to DEP's Bureau of Air Regulation (BAR).

## ~~III~~ V. SURFACE WATER DISCHARGES

Discharges into surface waters of the state during construction and operation of the project shall be in accordance with applicable provisions of 62-4, 62-160, 62-302, 62-601, 62-650, and 62-660, F.A.C., DEP Permit No. FL0030988-002-IW1S, and the following Conditions of Certification:

**A. Plant Effluents and Receiving Body of Water.**

For discharges made from the Martin Power Plant ~~CG/CC Project~~ the following conditions shall apply:

1. Receiving Body of Water (RBW). The receiving body of water has been determined by DEP to be (a) those waters of the discharge canal leading to the St. Lucie Canal which are considered to be waters of the state within the definition of Chapter 403, F .S., and (b) those water of the L-65 canal receiving cooling pond seepage from culverts 003a through 003e.

2. Points of Discharge (PODs). The points of discharge have been determine by DEP to be where the effluent physically enters the waters of the state in the discharge canal and the L-65 canal at the Outfall Serial Numbers (OSNs) 001, 002, and 003.

3. Thermal Limits. Heated water discharged at OSN 001 shall not be more than 5° F higher than the ambient (natural) temperature in the St. Lucie canal and shall not exceed 92° F. At all times under all conditions of stream flow the discharge temperature shall be controlled so that at least two thirds (2/3) of the width of the discharge canal's surface remains at ambient (natural) temperature. Further, no more than one fourth (1/4) of the cross section of the discharge canal at a traverse

# FLORIDA POWER & LIGHT COMPANY

## MANATEE UNIT 3
## POWER PLANT SITING APPLICATION
## PA-22-44

## FINAL ORDER OF CERTIFICATION AND EXCERPTS FROM CONDITIONS OF CERTIFICATION – SECTION XXIII - AIR

RRL-2
DOCKET NO. 040007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT _____
PAGES 1-21

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI EXHIBIT NO 6
COMPANY/ F. P. & L.
WITNESS: R. R. LaBauve (RRL-2)
DATE 11-08-04

**STATE OF FLORIDA**
**SITING BOARD**

| | | |
|---|---|---|
| **IN RE:** | **FLORIDA POWER & LIGHT COMPANY MANATEE UNIT 3 POWER PLANT SITING APPLICATION NO. PA 02-44.** | **OGC CASE NO.: 02-0317**<br>**DOAH CASE NO.: 02-0937EPP** |

## FINAL ORDER OF CERTIFICATION

On February 19, 2003, an administrative law judge with the Division of Administrative Hearings (DOAH) submitted his Recommended Order in this electrical power plant certification proceeding. Copies of the Recommended Order were served upon Mansota-88, Inc., and upon counsel for Florida Power & Light Company ("FPL"), Florida Department of Environmental Protection ("DEP"), Manatee County, Southwest Florida Water Management District ("SWFWMD"), Tampa Bay Regional Planning Council ("TBRPC"), and other designated agencies. A copy of the Recommended Order is attached as Exhibit A. The matter is now before the Governor and Cabinet, sitting as the "Siting Board," for final action under the Florida Electrical Power Plant Siting Act ("PPSA"). See §§ 403.501-403.518, Florida Statutes.

### BACKGROUND

On February 22, 2002, FPL filed a PPSA application for certification by the Siting Board of a proposed new electrical generating unit to be located at FPL's existing Manatee Plant site. The Manatee Plant site encompasses about 9,500 acres of property situated in a primarily agricultural and rural area of Manatee County, Florida. There are two existing electrical generating units at the Manatee Plant (Units 1 and 2). FPL proposes to construct and operate a new Unit 3 and related structures to be located on a 73-acre parcel within the existing Manatee Plant site (the "Project").

The proposed Unit 3 will be a 1100-megawatt combined-cycle electrical generating unit fueled solely by natural gas. The Project will consist of four combustion turbines, four heat recovery steam generators, one for each combustion turbine, and a new steam turbine. The Project will also involve the expansion of the existing on-site electrical system substation and the construction of several new appurtenant structures. FPL expects to commence construction of the Project in June of 2003. The planned in-service date for Unit 3 is June of 2005.

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DOAH PROCEEDINGS

After FPL's application was deemed to be complete, DEP forwarded the matter to DOAH and Administrative Law Judge Charles A. Stampelos ("ALJ") was assigned to the case. The ALJ held a land use hearing on the Project in August of 2002 and entered a subsequent Recommended Order concluding that the site of the Project is consistent and in compliance with the land use plans and zoning ordinances of Manatee County. By order dated December 9, 2002, the Siting Board adopted the ALJ's Recommended Order on land use and determined that the site of the Project is consistent and in compliance with the land use plans and zoning ordinances of Manatee County. On December 10, 2002, the Florida Public Service Commission issued its Final Order determining the need for Manatee Unit 3, pursuant to § 403.519, Florida Statutes.

On December 18, 2002, DEP issued its written Staff Analysis Report (Report) concerning the Project. The Report contained reports from other state, regional, and local agencies. The Report also compiled a set of proposed Conditions of Certification for Manatee Unit 3 proposed by DEP and the other agencies that reviewed the Project. On January 21, 2003, a joint prehearing stipulation was filed with DOAH indicating that no party to this proceeding objected to certification of the Project. During the subsequent certification hearing, DEP submitted a revised Staff Analysis Report (DEP Exhibit 2) updating and correcting various matters in the earlier version of its analysis, and revising the proposed Conditions of Certification.

The ALJ conducted a certification hearing in Manatee County on January 27, 2003, as required by § 403.508(3), Florida Statutes. Evidence was presented at this hearing by various parties, including FPL, DEP, and SWFWMD. Members of the general public were also allowed to offer testimony at the conclusion of the certification hearing. On February 19, 2003, the ALJ entered his Recommended Order on site certification in this case. The ALJ concluded that the competent, substantial evidence at the certification hearing "demonstrates that FPL has met its burden of proof to demonstrate that Manatee Unit 3 meets the criteria for certification under the PPSA." The ALJ recommended that "the Siting Board grant full and final certification" to FPL for the Manatee Unit 3 Project as described in FPL's application and the evidence presented at the certification hearing, and subject to the Conditions of Certification contained in DEP Exhibit 2 appended to the Recommended Order.

## CONCLUSION

The record in this case is devoid of objections by any governmental agencies to site certification of the Manatee Unit 3 Project. Furthermore, no Exceptions were filed in this case by any party challenging any of the factual findings, legal conclusions, or recommendation set forth in the ALJ's Recommended Order on site certification. Based on a review of the record and the governing law, the Siting Board concludes that the Manatee Unit 3 Project complies with the certification requirements of the PPSA and that site certification of the Project will fully balance the increasing demand for electrical power plant location and operation in this State with the broad interests of the public that are protected by the PPSA.

It is therefore ORDERED that:

A. The following clerical corrections are made to the Conditions of Certification for Manatee Unit 3 appended to the Recommended Order:[1]

1. The second unlabeled paragraph on page 15 is properly labeled as footnote "b." and the remaining four paragraphs on page 15 are relabeled as footnotes c. through f.

2. The table on page 27 is corrected by adding the "≤" (less than or equal to) sign immediately prior to the "Qriv" symbol for each of the six flow conditions of the Little Manatee River, as shown in the left hand column of the table.

B. The Recommended Order is otherwise adopted and incorporated by reference herein.

C. Certification of the location, construction, and continued operation of the Manatee Unit 3 Project as described in FPL's site certification application and by the evidence presented at the certification hearing is APPROVED, subject to the Conditions of Certification contained in DEP Exhibit 2 appended to the Recommended Order, as corrected in paragraph A above.

D. Authority to assure and enforce compliance by FPL and its agents with all of the Conditions of Certification imposed by this Final Order is hereby delegated to DEP, except that any proposed modification to burn a fuel other than natural gas shall be reviewed by the Siting Board.

Any party to this proceeding has the right to seek judicial review of the Final Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, M.S. 35, Tallahassee, Florida 32399-3000; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the

[1] An unopposed "Notice of Clerical Errors" was filed with the DEP Agency Clerk on behalf of FPL, DEP, and SWFWMD. These clerical corrections to portions of pages 15 and 27 of the Manatee Unit 3 Conditions of Certification are based on this Notice of Clerical Errors.

appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Final Order is filed with the clerk of the Department.

DONE AND ORDERED this 11 day of April, 2003, in Tallahassee, Florida, pursuant to a vote of the Governor and Cabinet, sitting as the Siting Board, at a duly noticed and constituted Cabinet meeting held on April 8, 2003.

THE GOVERNOR AND CABINET
SITTING AS THE SITING BOARD

THE HONORABLE JEB BUSH
GOVERNOR

FILED ON THIS DATE PURSUANT TO § 120.52, FLORIDA STATUTES, WITH THE DESIGNATED DEPARTMENT CLERK, RECEIPT OF WHICH IS HEREBY ACKNOWLEDGED.

CLERK

4/14/03
DATE

**CERTIFICATE OF SERVICE**

I HEREBY CERTIFY that a copy of the foregoing Final Order on Certification has been sent by United States Postal Service to:

Ross Stafford Burnaman, Esquire
James V. Antista, Esquire
Fish and Wildlife Conservation Commission
620 South Meridian Street
Tallahassee, FL 32399-1600

Roger Tucker, Esquire
Tampa Bay Regional Planning Council
9455 Koger Boulevard, Suite 219
St. Petersburg, FL 33702-2491

Peter C. Cunningham, Esquire
Douglas S. Roberts, Esquire
Hopping Green & Sams
Post Office Box 6526
Tallahassee, FL 32314-6526

Martha A. Moore, Esquire
Southwest Florida Water Management District
2379 Broad Street
Brooksville, FL 34604-6899

ManaSota-88, Inc.
c/o Glenn Compton, Chairman
419 Rubens Drive
Nokomis, Florida 34275

Ann Cole, Clerk and
Charles A. Stampelos, Administrative Law Judge
Division of Administrative Hearings
The DeSoto Building
1230 Apalachee Parkway
Tallahassee, FL 32399-1550

Colin Roopnarine, Esquire
Assistant General Counsel
Department of Community Affairs
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100

Jeffrey N. Steinsnyder, Esquire
Manatee County Attorney's Office
Post Office Box 1000
Bradenton, FL 34206

Sheauching Yu, Esquire
Department of Transportation
Haydon Burns Building, MS 58
605 Suwannee Street
Tallahassee, FL 32399-0450

Robert V. Elias, Esquire
Martha Carter Brown, Esquire
Florida Public Service Commission
Gerald Gunter Building
2450 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

and by hand delivery to:

Scott A. Goorland, Esquire
Department of Environmental Protection
3900 Commonwealth Blvd., M.S. 35
Tallahassee, FL 32399-3000

this 14th day of April, 2003.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

J. TERRELL WILLIAMS
Assistant General Counsel
3900 Commonwealth Blvd., M.S. 35
Tallahassee, FL 32399-3000
Telephone 850/245-2242

CONDITIONS OF CERTIFICATION: PA 02-44

FLORIDA POWER & LIGHT CORPORATION
MANATEE ELECTRIC POWER GENERATION FACILITY UNIT 3

## I. CERTIFICATION CONTROL

A. Under the control of these Conditions of Certification the Florida Power & Light Company (FPL) will operate an 1100 MW (nominal) facility consisting of four 170 MW combustion turbines, four heat recovery steam generators with duct burners, a 420 MW steam turbine and generator, and ancillary equipment. The facility is known as the Manatee Unit 3 and is located on a 72.8 acre site which is located within the existing 9,500 acre FPL Manatee site, Section 18, Township 33S, Range 20E, Manatee County, Florida.

B. These Conditions of Certification, unless specifically amended or modified, are binding upon the Licensee and shall apply to the construction and operation of the certified facility. If a conflict should occur between the design criteria of this project and the Conditions of Certification, the Conditions shall prevail unless amended or modified. In any conflict between any of these Conditions of Certification, the more specific condition governs.

## II. APPLICABLE RULES

The construction and operation of the certified facility shall be in accordance with all applicable provisions of Florida Statutes and Florida Administrative Code, including, but not limited to, the following regulations: Chapter 403, Florida Statutes (F.S.), and Chapters 40D-1, 40D-4, 40D-40, 40D-45, 62-4, 62-17, 62-256, 62-296, 62-297, 62-301, 62-302, 62-531, 62-532, 62-550, 62-555, 62-560, 62-600, 62-601, 62-604, 62-610, 62-620, 62-621, 62-650, 62-699, 62-660, 62-701, 62-762, 62-767, 62-769, and 62-770, Florida Administrative Code (F.A.C.), or their successors as they are renumbered.

## III. DEFINITIONS

Unless otherwise indicated herein, the meaning of terms used herein shall be governed by the definitions contained in Chapters 373 and 403, Florida Statutes, and any regulation adopted pursuant thereto. In the event of any dispute over the meaning of a term used in these conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative by the use of the commonly accepted meaning as determined by the Department. In addition, the following shall apply:

A. "DCA" shall mean the Florida Department of Community Affairs.

the applicable Conditions of Certification. If a violation of standards, harmful effects or irreversible environmental damage not anticipated by the application or the evidence presented at the certification hearing are detected during construction, the Licensee shall notify the DEP District Office as required by Condition VII, Compliance.

D. Reporting

Notice of commencement of construction shall be submitted to the Siting Coordination Office and the DEP Southwest District Office within fifteen (15) days after initiation. Starting three (3) months after construction commences, a quarterly construction status report shall be submitted to the DEP Southwest District Office. The report shall be a short narrative describing the progress of construction.

XXIII. AIR

A. General

1. The construction and operation of the Manatee Unit 3 project shall be in accordance with all applicable provisions of any Prevention of Significant Deterioration (PSD) Permit and/or Title V permit issued for Manatee Unit 3 and of any updates or modifications thereto, and of Chapters 62-210 through 62-297, F.A.C

2. All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the

Air Quality Division
DEP Southwest District Office
3804 Coconut Palm Dr.
Tampa, Florida 33619-8218.

Copies of all such documents shall also be submitted to

Air Section
Manatee County Environmental Management Department
202 Sixth Avenue East
Bradenton, Florida 34208.

B. Equipment

The permittee is authorized to install, tune, operate, and maintain four new General Electric Model PG7241FA gas turbine-electrical generator sets each with a nominal capacity of 170 MW (EU 006, 007, 008 and 009). Each gas turbine shall include the Speedtronic™ automated gas turbine control system . Ancillary equipment includes an inlet air filtration system, an evaporative inlet air cooling system, and a bypass stack for simple cycle operation The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before

combustion to increase overall unit efficiency. Gas-fired fuel heaters (EU 010) will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas.

2. Gas Turbine Controls

a. The permittee shall tune, maintain and operate the General Electric DLN-2.6 combustion system to control $NO_X$ emissions from each turbine. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the simple cycle permitted level for CO and NOx . Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

b. The permittee shall install, tune, maintain and operate a SCR system to control NOx emissions from each turbine during a combined cycle operation mode. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancilliary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip. *{Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions of 40 CFR 68}*

The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs). Each HRSG shall be designed to recover heat energy from one of the four gas turbines (3A-3D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). *{Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a nominal capacity of 470 MW.}*

C. The maximum heat input rate to each gas turbine is 1600 MMBtu/hr (normal conditions) based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of natural gas, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Air Quality Division, DEP Southwest District Office within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

D. The total maximum heat input rate to the duct burners for each HRSG is 495 MMBTU/hr based on the lower heating value (LHV) of the natural gas.

E. Subject to the restrictions and requirements of this certification, the gas turbines may operate under the following methods of operation.

1. Subject to the operational restrictions of this certification, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.

2. Each gas turbine shall fire natural gas as the primary fuel, which shall contain on average no more than 2 grains of sulfur per 100 standard cubic feet of natural gas.

3. Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a four-on-one combined cycle unit subject to the restrictions of this certification. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

4. When firing natural gas and operating in combined cycle mode, each gas turbine/HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.

5. Each gas turbine may operate individually in simple cycle mode to produce only direct, shaft-driven electrical power subject to the following operational restrictions.

a. Prior to demonstrating compliance in combined cycle mode, each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.

b. After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1000 hours per unit during any consecutive 12 months.

6. In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging" and may be used in either simple cycle or combined cycle modes.

7. When firing natural gas in either simple cycle or combined cycle modes, steam may be injected into each gas turbine to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall

log the date, time, and new mode of operation. Each gas turbine shall operate in this power augmentation mode no more than 400 hours per unit during any consecutive 12 months.

8. When firing natural gas, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. During any consecutive 12 months, each gas turbine shall operate in this peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. In addition, total combined operation of power augmentation and peaking modes shall not exceed 400 hours per unit during any consecutive 12 months.

F. Emissions from each gas turbine shall not exceed the following standards.

| Pollutant | Fuel | Method of Operation | Stack Test, 3-Run Average | | CEMS Block Average |
|---|---|---|---|---|---|
| | | | ppmvd @ 15% O2 | lb/hr | ppmvd @ 15% O2 |
| CO[a] | Gas | Simple Cycle | 7.4 | 27.5 | 8.0, 24-hr |
| | | Simple Cycle w/PA | 12.0 | 45.0 | 12.0, 24-hr |
| | | Combined Cycle, Normal Operation | 7.4 | 27.5 | 10.0, 24-hr |
| | | Combined Cycle, All Modes | NA | NA | 10.0, 24-hr |
| NOx[b] | Gas | Simple Cycle | 9.0 | 58.7 | 9.0, 24-hr |
| | | Simple Cycle w/PA | 12.0 | 76.2 | 12.0, 24-hr |
| | | Simple Cycle w/PK | 15.0 | 95.3 | 15.0, 24-hr |
| | | Combined Cycle w/SCR | 2.5 | 16.3 | 2.5, 24-hr |
| | | Combined Cycle w/SCR and DB | 2.5 | 23.6 | 2.5, 24-hr |
| | | Combined Cycle w/SCR, All Modes | N/A | N/A | 2.5, 24-hr |
| PM/PM10[c] | Gas | Simple or Combined Cycle | Fuel Specifications | | |
| | | Simple or Combined Cycle | Visible emissions shall not exceed 10% opacity for each 6-minute block average. | | |
| SAM/SO2[d] | Gas | Simple or Combined Cycle | Fuel Specifications | | |
| VOC[e] | Gas | Simple or Normal Combined Cycle | 1.3 | 2.8 | NA |
| VOC[e] | Gas | Combined Cycle, w/DB and/or PA | 4.0 | 10.5 | NA |

| | | | | | |
|---|---|---|---|---|---|
| Ammonia[f] | Gas | Combined Cycle w/SCR | 5 | NA | NA |

Notes:

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hr CO CEMS standard shall be determined separately for each mode of operation based on the hours of operation in each mode. {*Note*: 24-hr compliance average may be based on as little as 1-hr of data or as much as 24-hr of CEMS data}.

b. Compliance with the $NO_X$ standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. $NO_X$ mass emission rates are defined as oxides of nitrogen expressed as NO2. Compliance with the 24-hr $NO_X$ CEMS standards during simple cycle operation shall be determined separately for each method of operation based on the hours of operation for each method.

*{Note: A 24-hr compliance average may be based on as little as 1-hr of CEMS data or as much as 24-hr of CEMS data .}*

c. In its review for the prevention of Significant Deterioration permit for this facility, the Department determined that the fuel specifications combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM10 emissions. Note, however, that the specifications and emissions limitations in this certification do not establish BACT. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

*{Note: PM10 emissions for gas firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning.}*

d. In its review for the prevention of Significant Deterioration permit for this facility, the Department determined that the fuel sulfur specifications effectively limit the potential emissions of SAM and SO2 from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. Note, however, that the specifications and emissions limitations in this certification do not establish BACT.

*{Note: $SO_2$ emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SAM emissions are estimated to be less than 10% of the $SO_2$ emissions.}*

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may be also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Each SCR system shall be designed and operated for an initial ammonia slip target of less that 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

*{General Notes: "DB" means duct burning. "PA" means power augmentation. "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine*

*inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.}*

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G. The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60.

H. If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. When operating in this manner, each unit shall comply with the standards established for combined cycle operation with ammonia injection (SCR).

I. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and $NO_X$ from each gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify Air Quality Division, DEP Southwest District Office.

1. Each CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Air Quality Division, DEP Southwest District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

2. Each NOx monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR Part 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR Part 75. The RATA tests required for the $NO_X$ monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NOx monitor span values shall be set approximately considering the allowable method of operation and corresponding emission standards.

J. The oxygen (O2 ) content or carbon dioxide (CO2) content of the flue gas shall also be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEMS using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR Part 75.

K. Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd, corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NOx as specified in this certification. For purpose of determining compliance with the CEMS emission standard of this certification, missing (or excluded) data shall not be submitted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

L. A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block.

M. Each CEMS shall monitor and record emissions during all operations including all episodes of startup, shutdown, malfunction, DLN tuning, and steam blows. CEMS emissions data recorded during such episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Specific Conditions XXIII.W.4 and XXIII.W.7.

All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

N. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The report required in this certification shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this certification, except as otherwise authorized by the Department.

O. In accordance with the manufacturer's specifications, the permittee shall install, calibrate, maintain and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet allowable emissions levels over the range of load conditions allowed by this certification by comparing $NO_X$ emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During $NO_X$ monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load.

P. The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D.

Q. By the fifth calendar day of each month, the permittee shall record the following in a written or electronic log for each gas turbine for the previous month of operation: consumption of each fuel, the hours of operation, the hours of power augmentation, the hours of peaking, the hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D.

R. The permittee shall demonstrate compliance with the fuel sulfur specification of this certification by maintaining records of the sulfur content of the natural gas being supplied based on the vendor's analysis for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 (or more recent versions) in conjunction with the provisions of 40 CFR 75 Appendix D.

S. Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Air Quality Division, DEP Southwest District Office. The notification shall include a

preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Air Quality Division, DEP Southwest District Office, the permittee shall submit written quarterly reports report of the malfunctions.

T. Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Air Quality Division, DEP Southwest District Office summarizing emissions in excess of an NSPS standard. For purposes of reporting emissions in excess of NSPS standards, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS $NO_X$ emission standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard. For purposes of reporting emissions in excess of NSPS standards, excess emissions from duct firing are defined as: $NO_X$ or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO2 emissions in excess of the NSPS standards except during startup or shutdown.

U. Within 30 days following the end of each quarter, the permittee shall submit a report to the Air Quality Division, DEP Southwest District Office summarizing periods of excess emissions. The information shall be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

V. The permittee is authorized to install, operate, and maintain four fuel heaters fired exclusively with natural gas at a maximum heat input rate of 24 MMBtu per hour. The fuel heaters will be designed to preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. *{Note: In accordance with Air Permit No. PSD-FL-286, construction of two gas-fired fuel heaters has been completed.}*

W. Excess Emissions

1. In order to ensure that good operating practices to reduce emissions are followed, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.

2. Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data.

3. Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

4. Excess Emissions Allowed

a. As specified in this condition, excess emissions resulting from startup, shutdown, and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Air Quality Division, DEP Southwest District Office by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.

1) For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*

2) For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

3) For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

b. Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines.

5. Work Practice Standard and Load Restriction

a. Each unit will be operated according to manufacturer specifications and control systems. The CT control system is designed to reach Mode 5Q

(i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire.

b. A Best Operating Practice procedure for minimizing emissions during startup and shutdown shall be submitted to the Department within 60 days following determination of initial compliance with emission limits when operating in combined cycle mode.

c. Except for initial steam blows, startup and shutdown, malfunctions, commissioning and recommissioning, operation at loads where the DLN 2.6 system is not in pre-mix mode is prohibited.

6. Initial Steam Blows

a. Prior to completing the conversion from simple cycle to combined cycle operation, the permittee is authorized to operate each gas turbine at loads below 50% for the purpose of cleaning the HRSG piping system and piping connecting the HRSG to the steam turbine. Prior to conducting any steam blows, the permittee shall submit a proposed schedule. On the first day of conducting steam blows, the permittee shall notify the Air Quality Division, DEP Southwest District Office that the process has begun. The permittee shall complete this process within 90 days of conducting the initial steam blow. For good cause, the permittee may request that the Air Quality Division, DEP Southwest District Office extend the steam blow period. During the steam blows, the following conditions apply:

1) The permittee shall take all precautions to minimize the extent and duration of excess emissions.

2) Each gas turbine shall fire only natural gas and each CEMS shall be on line and functioning properly.

3) CO and $NO_X$ emissions may exceed the BACT limits specified in the PSD permit; however, $NO_X$ emissions shall not exceed the NSPS Subpart GG limit of 110 ppmvd corrected to 15% oxygen based on a 24-hour block average. If the NSPS standard is exceeded, the permittee shall notify the Air Quality Division, DEP Southwest District Office within one working day of the incident.

b. Within 30 days of completing the initial steam blows, the permittee shall submit a report to the Bureau of Air Regulation and the Air Quality Division, DEP Southwest District Office summarizing the daily emissions resulting from each steam blow. {Permitting Note: It is estimated that steam blows will occur intermittently over a 30-day period for each gas turbine/HRSG system followed by a similar 60-day period of intermittent steam blows for the common piping system serving the four interconnected combined cycle units. It is not expected that steam blows would occur every day during these periods. This condition only applies if simple cycle

operation begins prior to combined cycle operation and NSPS compliance tests for simple cycle operation have been performed}

7. CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Air Quality Division, DEP Southwest District Office with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.

X. Emissions Performance Testing

1. Required tests shall be performed in accordance with the following reference methods.

| Method | Description of Method and Comments |
|---|---|
| CTM-027 | Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.} |
| 7E | Determination of Nitrogen Oxide Emissions from Stationary Sources |
| 9 | Visual Determination of the Opacity of Emissions from Stationary Sources |
| 10 | Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.} |
| 18 | Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.} |
| 20 | Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines |
| 25A | Determination of Volatile Organic Concentrations |

Except for Method CTM-027, the above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". No other methods may be used for compliance testing unless prior written approval is received from the Department.

2. Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, $NO_X$, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum

production rate at which the unit will be operated for each unit configuration (i.e., simple cycle an combined cycle operation), but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested under all operating scenarios as required in Specific Condition No. 10. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NOx standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may also be used to demonstrate compliance with the CO and $NO_X$ mass emissions standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. Initial CO and VOC emissions tests performed during simple cycle operation may be used to satisfy the initial test requirement for similar operation in combined cycle mode. The Department may require the permittee to conduct additional tests after major replacement or repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc.

V. The permittee shall demonstrate continuous compliance with the CO and $NO_X$ emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds.

W. During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia slip. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Note: After initial compliance with the VOC standards are demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}*

X. If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions. Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst,

or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis

XXIX. WATER

The construction and operation of the Manatee Unit 3 project shall not cause or contribute to violation of any applicable provision of National Pollutant Discharge Elimination System (NPDES) Permit No. FL 0002267 Rev A or as subsequently revised, Chapters 62-4 through 62-699, F.A.C., and rules of the Department and the Southwest Florida Water Management District.

Any violation of such permit or rules shall constitute a violation of these conditions of certification.

XXX. DOMESTIC WASTE

The Licensee is hereby authorized to operate the facilities shown in the Manatee Unit 3 Site Certification Application and other documents on file with the Department and made a part hereof. The Licensee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment

XXXI. INDUSTRIAL WASTE

The Licensee is hereby authorized to operate the facilities shown in the Manatee Unit 3 Site Certification Application and other documents on file with the Department and made a part hereof and as specifically described in NPDES Permit No. FL 0002267 Rev A or as subsequently revised.

XXXII. SOLID AND HAZARDOUS WASTE

No solid or hazardous waste is to be permanently stored onsite.

XXXIII. WATER MANAGEMENT DISTRICT

A. Reports

1. All Water Management District-related reports required by the Site Certification shall be submitted to the Southwest Florida Water Management District on or before the fifteenth ($15^{th}$) day of the month, unless otherwise indicated, following data collection and shall be addressed to:

Permit Data Section, Records and Data Department
Southwest Florida Water Management District
2379 Broad Street

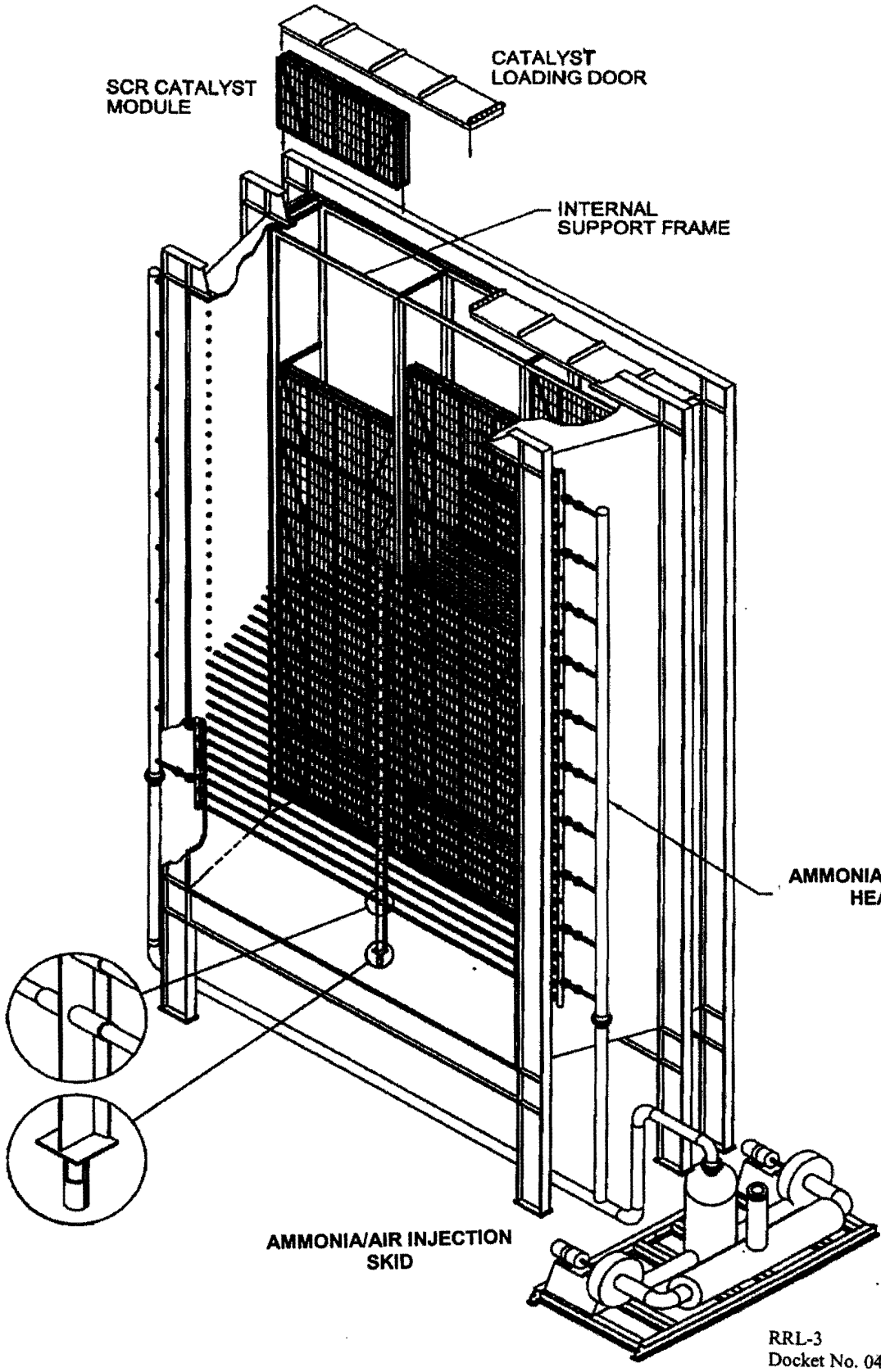
# FLORIDA POWER & LIGHT COMPANY

# DRAWING OF A TYPICAL SCR MODULE

RRL-3
DOCKET NO. 040007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT _____
PAGES 1-2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI EXHIBIT NO. 7
COMPANY/ F.P.&L.
WITNESS: R.R. LaBauve (RRL-3)
DATE 11-08-04

# TYPICAL SCR MODULE




RRL-3
Docket No. 040007-EI
FPL Witness R. R. LaBauve
Exhibit _____
Page 2 of 2

**EXHIBIT ___ (JP-1)**

**PROGRESS ENERGY FLORIDA, INC.**
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1A THROUGH 42-8A

**JANUARY 2003 - DECEMBER 2003**
FINAL TRUE-UP
DOCKET NO. 040007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI EXHIBIT NO. 8
COMPANY/ Progress
WITNESS. Javier Portuondo (JP-1)
DATE: 11-08-04

**PROGRESS ENERGY FLORIDA, INC.**

Form 42-1A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
**January 2003 through December 2003**
(in Dollars)

| Line | | Period Amount |
|---|---|---|
| 1 | Over/(Under) Recovery for the Period January 2003 - December 2003 (Form 42-2A, Line 5 + 6 + 10) | $ (9,871,507) |
| 2 | Estimated/Actual True-Up Amount approved for the period January 2003 - December 2003 (Order No. PSC-03-1348-FOF-EI) | (10,822,944) |
| 3 | Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2005 to December 2005 (Lines 1 - 2) | $ 951,437 |

**PROGRESS ENERGY FLORIDA, INC.**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
**January 2003 through December 2003**

Form 42-2A

End-of-Period True-Up Amount
(in Dollars)

| Line | Description | Actual January 03 | Actual February 03 | Actual March 03 | Actual April 03 | Actual May 03 | Actual June 03 | Actual July 03 | Actual August 03 | Actual September 03 | Actual October 03 | Actual November 03 | Actual December 03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ECRC Revenues (net of Revenue Taxes) | $378,105 | $356,537 | $302,100 | $325,794 | $373,149 | $428,997 | $436,788 | $426,601 | $457,010 | $389,149 | $354,880 | $340,796 | $4,569,907 |
| 2 | True-Up Provision | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | ECRC Revenues Applicable to Period (Lines 1 + 2) | 378,105 | 356,537 | 302,100 | 325,794 | 373,149 | 428,997 | 436,788 | 426,601 | 457,010 | 389,149 | 354,880 | 340,796 | 4,569,907 |
| 4 | Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| | a. O & M Activities (Form 42-5A, Line 9) | 7,100 | 93,932 | 89,177 | 400,755 | 520,349 | 1,830,170 | 1,254,431 | 1,524,721 | 2,009,561 | 3,571,613 | 2,106,638 | 997,621 | 14,406,068 |
| | b. Capital Investment Projects (Form 42-7A, Line 9) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 387 | 1,067 | 1,861 | 2,732 | 5,420 | 11,466 |
| | c. Total Jurisdictional ECRC Costs | 7,100 | 93,932 | 89,177 | 400,755 | 520,349 | 1,830,170 | 1,254,431 | 1,525,108 | 2,010,628 | 3,573,474 | 2,109,370 | 1,003,041 | 14,417,534 |
| 5 | Over/(Under) Recovery (Line 3 - Line 4c) | 371,005 | 262,605 | 212,923 | (74,961) | (147,200) | (1,401,173) | (817,643) | (1,098,507) | (1,553,617) | (3,184,325) | (1,754,490) | (662,245) | (9,847,628) |
| 6 | Interest Provision (Form 42-3A, Line 10) | 157 | 487 | 709 | 764 | 661 | (103) | (1,039) | (1,919) | (3,088) | (5,175) | (7,102) | (8,231) | (23,879) |
| 7 | Beginning Balance True-Up & Interest Provision | 0 | 371,162 | 634,254 | 847,886 | 773,689 | 627,150 | (774,126) | (1,592,808) | (2,693,234) | (4,249,939) | (7,439,439) | (9,201,031) | 0 |
| | a. Deferred True-Up from October 2002 to December 2002 (Order No. PSC-02-1735-FOF-E1) | (38,833) | (38,833) | (38,833) | (38,833) | (38,833) | (38,833) | (38,833) | (38,833) | (38,833) | (38,833) | (38,833) | (38,833) | (38,833) |
| 8 | True-Up Collected/(Refunded) (see Line 2) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | End of Period Total True-Up (Lines 5+6+7+7a+8) | 332,329 | 595,421 | 809,053 | 734,856 | 588,317 | (812,959) | (1,631,641) | (2,732,067) | (4,288,772) | (7,478,272) | (9,239,864) | (9,910,340) | (9,910,340) |
| 10 | Adjustments to Period Total True-Up Including Interest | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | End of Period Total True-Up (Lines 9 + 10) | $332,329 | $595,421 | $809,053 | $734,856 | $588,317 | ($812,959) | ($1,631,641) | ($2,732,067) | ($4,288,772) | ($7,478,272) | ($9,239,864) | ($9,910,340) | ($9,910,340) |

**Docket No. 040007-EI**
**Progress Energy Florida, Inc.**
**J. Portuondo Exhibit ____ (JP-1)**
**Jan. 2003-Dec. 2003 Final True-Up**

Form 42-3A

**PROGRESS ENERGY FLORIDA, INC.**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
**January 2003 through December 2003**

Interest Provision
(in Dollars)

| Line | Description | Actual January 03 | Actual February 03 | Actual March 03 | Actual April 03 | Actual May 03 | Actual June 03 | Actual July 03 | Actual August 03 | Actual September 03 | Actual October 03 | Actual November 03 | Actual December 03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10) | ($38,833) | $332,329 | $595,421 | $809,053 | $734,856 | $588,317 | ($812,959) | ($1,631,641) | ($2,732,067) | ($4,288,772) | ($7,478,272) | ($9,239,864) | |
| 2 | Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5 + 8) | 332,172 | 594,934 | 808,344 | 734,092 | 587,656 | (812,856) | (1,630,602) | (2,730,148) | (4,285,684) | (7,473,097) | (9,232,762) | (9,902,109) | |
| 3 | Total of Beginning & Ending True-Up (Lines 1 + 2) | 293,339 | 927,263 | 1,403,765 | 1,543,145 | 1,322,512 | (224,539) | (2,443,561) | (4,361,789) | (7,017,751) | (11,761,870) | (16,711,034) | (19,141,973) | |
| 4 | Average True-Up Amount (Line 3 x 1/2) | 146,670 | 463,632 | 701,883 | 771,573 | 661,256 | (112,270) | (1,221,781) | (2,180,895) | (3,508,876) | (5,880,935) | (8,355,517) | (9,570,987) | |
| 5 | Interest Rate (First Day of Reporting Business Month) | 1.29% | 1.27% | 1.25% | 1.18% | 1.19% | 1.21% | 1.00% | 1.05% | 1.06% | 1.06% | 1.05% | 1.00% | |
| 6 | Interest Rate (First Day of Subsequent Business Month) | 1.27% | 1.25% | 1.18% | 1.19% | 1.21% | 1.00% | 1.05% | 1.06% | 1.06% | 1.05% | 1.00% | 1.06% | |
| 7 | Total of Beginning & Ending Interest Rates (Lines 5 + 6) | 2.56% | 2.52% | 2.43% | 2.37% | 2.40% | 2.21% | 2.05% | 2.11% | 2.12% | 2.11% | 2.05% | 2.06% | |
| 8 | Average Interest Rate (Line 7 x 1/2) | 1.280% | 1.260% | 1.215% | 1.185% | 1.200% | 1.105% | 1.025% | 1.055% | 1.060% | 1.055% | 1.025% | 1.030% | |
| 9 | Monthly Average Interest Rate (Line 8 x 1/12) | 0.107% | 0.105% | 0.101% | 0.099% | 0.100% | 0.092% | 0.085% | 0.088% | 0.088% | 0.088% | 0.085% | 0.086% | |
| 10 | Interest Provision for the Month (Line 4 x Line 9) | $157 | $487 | $709 | $764 | $661 | ($103) | ($1,039) | ($1,919) | ($3,088) | ($5,175) | ($7,102) | ($8,231) | ($23,879) |

**Docket No. 040007-EI**
**Progress Energy Florida, Inc.**
**J. Portuondo Exhibit ____ (JP-1)**
**Jan. 2003-Dec. 2003 Final True-Up**

**PROGRESS ENERGY FLORIDA, INC.**

Form 42-4A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
**January 2003 through December 2003**

Variance Report of O&M Activities
(In Dollars)

| Line | | (1) Actual | (2) Estimated/Actual Projection | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | |
| 1 | Substation Environmental Investigation, Remediation, and Pollution Prevention | 581,674 | 473,260 | 108,414 | 22.9% |
| 1a | Substation Environmental Investigation, Remediation, and Pollution Prevention - Costs | (25,000) | (25,000) | 0 | 0.0% |
| 2 | Distribution System Environmental Investigation, Remediation, and Pollution Prevention | 14,070,895 | 14,970,455 | (899,560) | -6.0% |
| 3a | Pipeline Integrity Management | 0 | 10,000 | (10,000) | -100.0% |
| 4 | Above Ground Tank Secondary Containment | 0 | 0 | 0 | 0.0% |
| 2 | Total O&M Activities | 14,627,568 | 15,428,715 | (801,147) | -5.2% |
| 3 | Recoverable Costs Allocated to Energy | 0 | 0 | 0 | 0.0% |
| 4 | Recoverable Costs Allocated to Demand | 14,627,568 | 15,428,715 | (801,147) | -5.2% |

Notes:

Column (1) is the End of Period Totals on Form 42-5A
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Docket No. 040007-EI
Progress Energy Florida, Inc.
J. Portuondo Exhibit ____ (JP-1)
Jan. 2003-Dec. 2003 Final True-Up
Page 5 of 12

**PROGRESS ENERGY FLORIDA, INC.**

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
**January 2003 through December 2003**

Form 42-5A

O&M Activities
(in Dollars)

| Line | Description | Actual January 03 | Actual February 03 | Actual March 03 | Actual April 03 | Actual May 03 | Actual June 03 | Actual July 03 | Actual August 03 | Actual September 03 | Actual October 03 | Actual November 03 | Actual December 03 | End of Period Total | Method of Classification Demand | Method of Classification Energy | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | | | | | | | | | | | | | | |
| 1 | Substation Environmental Investigation, Remediation, and Pollution Prevention | 7,007 | 28,335 | 62,721 | 190,840 | 52,835 | (215) | (18,796) | 2,357 | 97,379 | 4,002 | 83,239 | 71,971 | 581,674 | $ 581,674 | $ - | Transmission | Transmission maintenance is allocated on demand |
| 1a | Substation Environmental Investigation, Remediation, and Pollution Prevention - Costs included in Base Rates | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,084) | (2,083) | (2,086) | (25,000) | $ (25,000) | $ - | Transmission | Transmission maintenance is allocated on demand |
| 2 | Distribution System Environmental Investigation, Remediation, and Pollution Prevention | 3,566 | 75,356 | 45,663 | 265,885 | 486,038 | 1,840,496 | 1,275,496 | 1,531,738 | 1,950,022 | 3,587,124 | 2,057,804 | 951,707 | 14,070,895 | $ 14,070,895 | $ - | Distribution | Distribution maintenance is allocated on demand |
| 3a | Pipeline Intagrity Management, Review/Update Plan and Risk Assessments | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $ - | $ - | Production | Production maintenance is allocated on demand |
| 4 | Above Ground Tank Secondary Containment | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $ - | $ - | Production | Production maintenance is allocated on demand |
| 2 | Total of O&M Activities | 8,489 | 101,608 | 106,301 | 454,643 | 536,790 | 1,838,198 | 1,254,616 | 1,532,012 | 2,045,318 | 3,589,042 | 2,138,960 | 1,021,591 | 14,627,568 | $ 14,627,568 | $ - | | |
| 3 | Recoverable Costs Allocated to Energy - Transm | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | | | |
| 4 | Recoverable Costs Allocated to Demand - Transm | 4,924 | 26,252 | 60,638 | 188,757 | 50,752 | (2,298) | (20,861) | 274 | 95,298 | 1,918 | 81,156 | 69,885 | 556,674 | | | | |
| | Recoverable Costs Allocated to Demand - Distrib | 3,566 | 75,356 | 45,663 | 265,885 | 486,038 | 1,840,496 | 1,275,496 | 1,531,738 | 1,950,022 | 3,587,124 | 2,057,804 | 951,707 | 14,070,895 | | | | |
| | Recoverable Costs Allocated to Demand - Prod | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | | | |
| 5 | Retail Transmission Energy Jurisdictional Factor | 0.98400 | 0.97430 | 0.97540 | 0.97570 | 0.98000 | 0.97680 | 0.97940 | 0.97650 | 0.97770 | 0.97510 | 0.97490 | 0.98250 | | | | | |
| 6 | Retail Transmission Demand Jurisdictional Factor | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | | | | | |
| | Retail Distribution Demand Jurisdictional Factor | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | | | | | |
| | Retail Production Demand Jurisdictional Factor - Intrmd | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | | | | | |
| 7 | Jurisdictional Energy Recoverable Costs - Transm (A) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | | | |
| 8 | Jurisdictional Demand Recoverable Costs - Transm (B) | 3,551 | 18,931 | 43,729 | 136,122 | 36,600 | (1,657) | (15,058) | 198 | 68,723 | 1,384 | 58,526 | 50,397 | 401,446 | | | | |
| | Jurisdictional Demand Recoverable Costs - Distrib (B) | 3,549 | 75,001 | 45,448 | 264,633 | 483,749 | 1,831,827 | 1,269,489 | 1,524,523 | 1,940,836 | 3,570,229 | 2,048,112 | 947,224 | 14,004,822 | | | | |
| | Jurisdictional Demand Recoverable Costs - Prod-Intrmd (B) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | | | |
| 9 | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $7,100 | $93,932 | $89,177 | $400,755 | $520,349 | $1,830,170 | $1,254,431 | $1,524,721 | $2,009,561 | $3,571,613 | $2,106,638 | $997,621 | $14,406,068 | | | | |

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

**Docket No. 040007-EI**
**Progress Energy Florida, Inc.**
**J. Portuondo Exhibit ____ (JP-1)**
**Jan. 2003-Dec. 2003 Final True-Up**
**Page 6 of 12**

**PROGRESS ENERGY FLORIDA, INC.**

Form 42-6A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
**January 2003 through December 2003**

Variance Report of Capital Investment Projects - Recoverable Costs
(In Dollars)

| Line | (1) Actual | (2) Estimated/Actual Projection | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|
| 1 Description of Capital Investment Activities | | | | |
| 3b Pipeline Integrity Management - Bartow/Anclote Pipeline | 9,498 | 20,686 | (11,188) | -54.1% |
| 4a Above Ground Tank Secondary Containment - Turner CT's | 2,827 | 5,662 | (2,835) | -50.1% |
| 4b Above Ground Tank Secondary Containment - Bartow CT's | 447 | 1,074 | (627) | -58.4% |
| 4c Above Ground Tank Secondary Containment - Crystal River 1 & 2 | 836 | 3,687 | (2,851) | -77.3% |
| 2 Total Capital Investment Activities | 13,608 | 31,109 | (17,501) | -56.3% |
| 3 Recoverable Costs Allocated to Energy | 0 | 0 | 0 | 0.0% |
| 4 Recoverable Costs Allocated to Demand | 13,608 | 31,109 | (17,501) | -56.3% |

Notes:

Column (1) is the End of Period Totals on Form 42-7A
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

**PROGRESS ENERGY FLORIDA, INC.**

Form 42-7A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
**January 2003 through December 2003**

Capital Investment Projects-Recoverable Costs
(in Dollars)

| Line | Description | Actual January 03 | Actual February 03 | Actual March 03 | Actual April 03 | Actual May 03 | Actual June 03 | Actual July 03 | Actual August 03 | Actual September 03 | Actual October 03 | Actual November 03 | Actual December 03 | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects (A) | | | | | | | | | | | | | | | |
| | 3b Pipeline Integrity Management - Bartow/Anclote Pipeline | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $447 | $1,232 | $1,968 | $2,793 | $3,058 | $9,498 | $9,498 | $0 |
| | 4a Above Ground Tank Secondary Containment - Turner CTs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,827 | 2,827 | 2,827 | 0 |
| | 4b Above Ground Tank Secondary Containment - Bartow CTs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 447 | 447 | 447 | 0 |
| | 4c Above Ground Tank Secondary Containment - Crystal River 1&2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 164 | 327 | 345 | 836 | 836 | 0 |
| 2 | Total Investment Projects - Recoverable Costs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 447 | 1,232 | 2,132 | 3,120 | 6,677 | 13,608 | $13,608 | $0 |
| 3 | Recoverable Costs Allocated to Energy | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| 4 | Recoverable Costs Allocated to Demand - Production - Base | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 164 | 327 | 345 | 836 | | |
| | Recoverable Costs Allocated to Demand - Production - Intermediate | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 447 | 1,232 | 1,968 | 2,793 | 3,058 | 9,498 | | |
| | Recoverable Costs Allocated to Demand - Production - Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,274 | 3,274 | | |
| 5 | Retail Energy Jurisdictional Factor | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | | |
| 6 | Retail Demand Jurisdictional Factor - Production - Base | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.9595700 | 0.9595700 | 0.9595700 | | | |
| | Retail Demand Jurisdictional Factor - Production - Intermediate | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.8657400 | 0.8657400 | 0.8657400 | 0.8657400 | 0.8657400 | | | |
| | Retail Demand Jurisdictional Factor - Production - Peaking | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.7456200 | 0.7456200 | 0.7456200 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| 8 | Jurisdictional Demand Recoverable Costs - Production - Base (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 157 | 314 | 331 | 802 | | |
| | Jurisdictional Demand Recoverable Costs - Production - Intermediate (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 387 | 1,067 | 1,704 | 2,418 | 2,647 | 8,223 | | |
| | Jurisdictional Demand Recoverable Costs - Production - Peaking (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,441 | 2,441 | | |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $387 | $1,067 | $1,861 | $2,732 | $5,420 | $11,466 | | |

Notes:

(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

**Docket No. 040007-EI**
**Progress Energy Florida, Inc.**
**J. Portuondo Exhibit ____ (JP-1)**
**Jan. 2003-Dec. 2003 Final True-Up**

**PROGRESS ENERGY FLORIDA, INC.**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
**January 2003 through December 2003**

Form 42-8A
Page 1 of 4

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3b)
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Actual January 03 | Actual February 03 | Actual March 03 | Actual April 03 | Actual May 03 | Actual June 03 | Actual July 03 | Actual August 03 | Actual September 03 | Actual October 03 | Actual November 03 | Actual December 03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $80,590 | $60,759 | $71,838 | $76,877 | ($29,100) | |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3 | Less: Accumulated Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 80,590 | 141,349 | 213,187 | 290,064 | 260,964 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 80,590 | 141,349 | 213,187 | 290,064 | 260,964 | |
| 6 | Average Net Investment | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 40,295 | 110,970 | 177,268 | 251,625 | 275,514 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) | 10.75% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 361 | 994 | 1,588 | 2,254 | 2,468 | $7,665 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) | 2.57% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 86 | 238 | 380 | 539 | 590 | 1,833 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (E) | 3.60% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization (F) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (J) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other (G) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 447 | 1,232 | 1,968 | 2,793 | 3,058 | 9,498 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 447 | 1,232 | 1,968 | 2,793 | 3,058 | 9,498 |
| 10 | Energy Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor - Production (Intermediate) | | | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.8657400 | 0.8657400 | 0.8657400 | 0.8657400 | 0.8657400 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 387 | 1,067 | 1,704 | 2,418 | 2,647 | 8,223 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $387 | $1,067 | $1,704 | $2,418 | $2,647 | $8,223 |

Notes:

(A) Description and reason for 'Other' adjustments to net investment. None for this period.
(B) Applicable beginning of period and and of period depreciable base by plant name(s), unit(s), or plant account(s).
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Bartow/Anclote Pipeline.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 3.60% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Amortization period is approximately 28 years for Bartow/Anclote Pipeline.
(G) Description and reason for 'Other' adjustments to investment expenses. None for this period.
(H) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(I) Line 9b x Line 11
(J) Lines 2 + 3 x 89% @ .0183381 x 1/12 + 11% @ .0196598 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2002 Actual Property Tax Milage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

Docket No. 040007-EI
Progress Energy Florida, Inc.
J. Portuondo Exhibit ____ (JP-1)
Jan. 2003-Dec. 2003 Final True-Up
Page 9 of 12

**PROGRESS ENERGY FLORIDA, INC.**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
**January 2003 through December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4a)
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Actual January 03 | Actual February 03 | Actual March 03 | Actual April 03 | Actual May 03 | Actual June 03 | Actual July 03 | Actual August 03 | Actual September 03 | Actual October 03 | Actual November 03 | Actual December 03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $509,360 | |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3 | Less: Accumulated Depreciation (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 509,360 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 509,360 | |
| 6 | Average Net Investment | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 254,680 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) 10.75% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,282 | $2,282 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) 2.57% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 545 | 545 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (E) 4.80% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (J) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,827 | 2,827 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,827 | 2,827 |
| 10 | Energy Jurisdictional Factor | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor - Production (Peaking) | | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.7456200 | 0.7456200 | 0.7456200 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,108 | 2,108 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,108 | $2,108 |

Notes:

(A) Description and reason for 'Other' adjustments to net investment. None for this period.
(B) Applicable beginning of period and end of period depreciable base by plant name(s), unit(s), or plant account(s).
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Turner CTs.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 4.80% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Amortization period is approximately 21 years for Above Ground Tank Secondary Containment - Turner CTs.
(G) Description and reason for 'Other' adjustments to investment expenses. None for this period.
(H) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(I) Line 9b x Line 11
(J) Lines 2 + 3 x .020912 x 1/12. Based on 2002 Actual Property Tax Milage Rate.

Source:

Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

**PROGRESS ENERGY FLORIDA, INC.**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
**January 2003 through December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4b)
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Actual January 03 | Actual February 03 | Actual March 03 | Actual April 03 | Actual May 03 | Actual June 03 | Actual July 03 | Actual August 03 | Actual September 03 | Actual October 03 | Actual November 03 | Actual December 03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $80,575 | |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3 | Less: Accumulated Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 80,575 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 80,575 | |
| 6 | Average Net Investment | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 40,287 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) | 10.75% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 361 | $361 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) | 2.57% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 86 | 86 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (E) | 5.70% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization (F) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (J) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other (G) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 447 | 447 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 447 | 447 |
| 10 | Energy Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor - Production (Peaking) | | | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.7456200 | 0.7456200 | 0.7456200 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 333 | 333 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $333 | $333 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment. None for this period.
(B) Applicable beginning of period and end of period depreciable base by plant name(s), unit(s), or plant account(s).
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Bartow CTs.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 5.70% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Amortization period is approximately 21 years for Above Ground Tank Secondary Containment - Bartow CTs.
(G) Description and reason for 'Other' adjustments to investment expenses. None for this period.
(H) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(I) Line 9b x Line 11
(J) Lines 2 + 3 x .018338 x 1/12. Based on 2002 Actual Property Tax Milage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

**PROGRESS ENERGY FLORIDA, INC.**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
**January 2003 through December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4c)
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Actual January 03 | Actual February 03 | Actual March 03 | Actual April 03 | Actual May 03 | Actual June 03 | Actual July 03 | Actual August 03 | Actual September 03 | Actual October 03 | Actual November 03 | Actual December 03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $29,470 | $0 | $3,249 | |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3 | Less: Accumulated Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 29,470 | 29,470 | 32,719 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 29,470 | 29,470 | 32,719 | |
| 6 | Average Net Investment | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14,735 | 29,470 | 31,095 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) | 10.75% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 132 | 264 | 279 | $675 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) | 2.57% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 32 | 63 | 67 | 161 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (E) | 5.30% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization (F) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (J) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other (G) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 164 | 327 | 345 | 836 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 164 | 327 | 345 | 836 |
| 10 | Energy Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor - Production (Base) | | | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.0000000 | 0.9595700 | 0.9595700 | 0.9595700 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 157 | 314 | 331 | 802 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $157 | $314 | $331 | $802 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment. None for this period.
(B) Applicable beginning of period and end of period depreciable base by plant name(s), unit(s), or plant account(s).
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Crystal River 1&2.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 5.3% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Amortization period is approximately 28 years for Above Ground Tank Secondary Containment - Crystal River 1&2.
(G) Description and reason for 'Other' adjustments to investment expenses. None for this period.
(H) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(I) Line 9b x Line 11
(J) Lines 2 + 3 x .018338 x 1/12. Based on 2002 Actual Property Tax Milage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

EXHIBIT No. __ (JP-2)
Revised - September 3, 2004

ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1E THROUGH 42-8E

**JANUARY 2004 - DECEMBER 2004**
Calculation of the Current Period Estimated/Actual Amount
Actuals for the period of January through June 2004
Estimated for the period of July through December 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI EXHIBIT NO 9
COMPANY/ Progress
WITNESS: Javier Portuondo (JP-2)
DATE 11-08-04

**PROGRESS ENERGY FLORIDA**

Form 42-1E

0

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
**January 2004 through December 2004**
(in Dollars)

| Line | | Period Amount |
|---|---|---|
| 1 | Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5) | $ (18,590,037) |
| 2 | Interest Provision (Form 42-2E, Line 6) | (100,297) |
| 3 | Sum of Current Period Adjustments (Form 42-2E, Line 10) | (336,932) |
| 4 | Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2005 to December 2005 (Lines 1 + 2 +3) | **$ (19,027,266)** |

Docket No. 040007-EI
Progress Energy Florida
Exhibit No. ____ (JP-2)
(Revised Sept. 3, 2004)
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**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
**January 2004 to December 2004**

Form 42-2E
0

**End-of-Period True-Up Amount**
(in Dollars)

| Line | Description | | Actual January 04 | Actual February 04 | Actual March 04 | Actual April 04 | Actual May 04 | Actual June 04 | Estimated July 04 | Estimated August 04 | Estimated September 04 | Estimated October 04 | Estimated November 04 | Estimated December 04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ECRC Revenues (net of Revenue Taxes) | | $1,658,785 | $1,449,955 | $1,478,097 | $1,409,342 | $1,582,566 | $1,996,438 | $2,091,840 | $2,099,599 | $2,113,331 | $1,904,789 | $1,625,210 | $1,587,432 | $20,997,381 |
| 2 | True-Up Provision | (10,861,777) | (910,536) | (905,148) | (905,148) | (905,148) | (905,148) | (905,148) | (905,148) | (905,148) | (905,148) | (905,148) | (905,148) | (905,148) | (10,867,165) |
| 3 | ECRC Revenues Applicable to Period (Lines 1 + 2) | | 748,249 | 544,807 | 572,949 | 504,194 | 677,418 | 1,091,288 | 1,186,692 | 1,194,451 | 1,208,183 | 999,640 | 720,062 | 682,284 | 10,130,216 |
| 4 | Jurisdictional ECRC Costs | | | | | | | | | | | | | | |
| | a. O & M Activities (Form 42-5E, Line 9) | | 493,310 | 555,730 | 916,193 | 617,307 | 665,490 | 808,690 | 1,057,192 | 4,341,465 | 4,418,576 | 4,673,043 | 4,254,949 | 5,193,654 | 27,995,599 |
| | b. Capital Investment Projects (Form 42-7E, Line 9) | | 4,491 | 9,945 | 35,297 | 35,496 | 5,801 | 1,228 | 83,110 | 154,095 | 133,819 | 111,979 | 90,954 | 58,638 | 724,654 |
| | c. Total Jurisdictional ECRC Costs | | 497,801 | 565,675 | 951,490 | 652,803 | 671,291 | 809,916 | 1,140,302 | 4,495,560 | 4,552,195 | 4,785,022 | 4,345,903 | 5,252,293 | 28,720,253 |
| 5 | Over/(Under) Recovery (Line 3 - Line 4c) | | 250,448 | (20,868) | (378,541) | (148,609) | 6,127 | 281,370 | 46,390 | (3,301,110) | (3,344,013) | (3,785,361) | (3,625,842) | (4,570,009) | (18,590,037) |
| 6 | Interest Provision (Form 42-3E, Line 10) | | (8,122) | (6,989) | (6,250) | (5,869) | (5,297) | (5,064) | (4,871) | (5,678) | (6,368) | (11,329) | (14,450) | (18,010) | (100,297) |
| 7 | Beginning Balance True-Up & Interest Provision | | (10,867,165) | (9,714,303) | (8,837,012) | (8,316,655) | (7,565,985) | (8,660,007) | (5,478,553) | (4,868,816) | (7,270,457) | (9,717,890) | (12,609,252) | (15,344,395) | (10,867,165) |
| | a. Deferred True-Up from January 2003 to December 2003 (Order No. PSC-03-1348-FOF-E1) | | 951,437 | 951,437 | 951,437 | 951,437 | 951,437 | 951,437 | 951,437 | 951,437 | 951,437 | 951,437 | 951,437 | 951,437 | 951,437 |
| 8 | True-Up Collected/(Refunded) (see Line 2) | | 910,536 | 905,148 | 905,148 | 905,148 | 905,148 | 905,148 | 905,148 | 905,148 | 905,148 | 905,148 | 905,148 | 905,148 | 10,867,165 |
| 9 | End of Period Total True-Up (Lines 5+6+7+7a+8) | | (6,762,866) | (7,885,575) | (7,365,218) | (6,814,548) | (5,708,570) | (4,527,116) | (3,580,449) | (6,319,020) | (8,766,253) | (11,857,815) | (14,392,958) | (18,075,829) | (17,738,897) |
| 10 | Adjustments to Period Total True-Up Including Interest (a) | | 0 | 0 | 0 | 0 | 0 | 0 | (336,932) | 0 | 0 | 0 | 0 | 0 | (336,932) |
| 11 | End of Period Total Net True-Up (Lines 9 + 10) | | ($6,762,866) | ($7,885,575) | ($7,365,218) | ($6,814,548) | ($5,708,570) | ($4,527,116) | ($3,917,381) | ($6,319,020) | ($8,766,253) | ($11,857,815) | ($14,392,958) | ($18,075,829) | ($18,075,829) |

**(a) Adjustment - 2003 FPSC Audit - Docket 040007-EI, Audit Control No. 04-444-2-2.**

Docket No. 040007-EI
Progress Energy Florida
Exhibit No. ____ (JP-2)
(Revised Sept. 3, 2004)
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**PROGRESS ENERGY FLORIDA**

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
**January 2004 to December 2004**

Form 42-3E
0

**Interest Provision**
(in Dollars)

| Line | Description | Actual January 04 | Actual February 04 | Actual March 04 | Actual April 04 | Actual May 04 | Actual June 04 | Estimated July 04 | Estimated August 04 | Estimated September 04 | Estimated October 04 | Estimated November 04 | Estimated December 04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10) | ($9,915,728) | ($8,762,866) | ($7,885,575) | ($7,365,218) | ($6,614,548) | ($5,708,570) | ($4,864,048) | ($3,917,381) | ($6,319,020) | ($8,766,253) | ($11,657,815) | ($14,392,958) | |
| 2 | Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8) | (8,754,744) | (7,878,586) | (7,358,968) | (6,608,679) | (5,703,273) | (4,522,052) | (3,912,510) | (6,313,342) | (8,757,885) | (11,646,486) | (14,378,508) | (18,057,819) | |
| 3 | Total of Beginning & Ending True-Up (Lines 1 + 2) | (18,670,472) | (16,641,452) | (15,244,543) | (13,973,897) | (12,317,821) | (10,230,622) | (8,776,557) | (10,230,723) | (15,076,905) | (20,412,738) | (26,036,323) | (32,450,777) | |
| 4 | Average True-Up Amount (Line 3 x 1/2) | (9,335,236) | (8,320,726) | (7,622,272) | (6,986,949) | (6,158,911) | (5,115,311) | (4,388,279) | (5,115,362) | (7,538,453) | (10,206,369) | (13,018,162) | (16,225,389) | |
| 5 | Interest Rate (First Day of Reporting Business Month) | 1.06% | 1.03% | 0.98% | 0.98% | 1.03% | 1.04% | 1.33% | 1.33% | 1.33% | 1.33% | 1.33% | 1.33% | |
| 6 | Interest Rate (First Day of Subsequent Business Month) | 1.03% | 0.98% | 0.98% | 1.03% | 1.04% | 1.33% | 1.33% | 1.33% | 1.33% | 1.33% | 1.33% | 1.33% | |
| 7 | Total of Beginning & Ending Interest Rates (Lines 5 + 6) | 2.09% | 2.01% | 1.96% | 2.01% | 2.07% | 2.37% | 2.66% | 2.66% | 2.66% | 2.66% | 2.66% | 2.66% | |
| 8 | Average Interest Rate (Line 7 x 1/2) | 1.045% | 1.005% | 0.980% | 1.005% | 1.035% | 1.185% | 1.330% | 1.330% | 1.330% | 1.330% | 1.330% | 1.330% | |
| 9 | Monthly Average Interest Rate (Line 8 x 1/12) | 0.087% | 0.084% | 0.082% | 0.084% | 0.086% | 0.099% | 0.111% | 0.111% | 0.111% | 0.111% | 0.111% | 0.111% | |
| 10 | Interest Provision for the Month (Line 4 x Line 9) | ($8,122) | ($6,989) | ($6,250) | ($5,869) | ($5,297) | ($5,064) | ($4,871) | ($5,678) | ($8,368) | ($11,329) | ($14,450) | ($18,010) | ($100,297) |

**PROGRESS ENERGY FLORIDA**

Form 42 4E
0

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
**January 2004 to December 2004**

**Variance Report of O&M Activities**
(In Dollars)

| Line | | (1) Estimated/ Actual | (2) Original Projection | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | |
| 1 | Substation Environmental Investigation, Remediation, and Pollution Prevention | 321,684 | 754,353 | (432,669) | -57% |
| 1a | Substation Environmental Investigation, Remediation, and Pollution Prevention - Costs | (25,000) | (25,000) | 0 | 0% |
| 2 | Distribution System Environmental Investigation, Remediation, and Pollution Prevention | 8,098,387 | 5,168,353 | 2,930,034 | 57% |
| 3a | Pipeline Integrity Management | 990,000 | 245,000 | 745,000 | 304% |
| 4 | Above Ground Tank Secondary Containment | 0 | 0 | 0 | 0% |
| 5 | SO2 Emissions Allowances | 19,902,833 | 4,400,000 | 15,502,833 | 352% |
| 6 | 316(b) Clean Water Act | 0 | 0 | 0 | 0% |
| 2 | Total O&M Activities - Recoverable Costs | 29,287,905 | 10,542,706 | 18,745,199 | 178% |
| 3 | Recoverable Costs Allocated to Energy | 19,902,833 | 4,400,000 | 15,502,833 | 352% |
| 4 | Recoverable Costs Allocated to Demand | 9,385,071 | 6,142,706 | 3,242,365 | 53% |

Notes:

Column (1) is the End of Period Totals on Form 42-5E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

**PROGRESS ENERGY FLORIDA**

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
**January 2004 to December 2004**

Form 42-5E
0

**O&M Activities**
(In Dollars)

| Line | Description | Actual January 04 | Actual February 04 | Actual March 04 | Actual April 04 | Actual May 04 | Actual June 04 | Estimated July 04 | Estimated August 04 | Estimated September 04 | Estimated October 04 | Estimated November 04 | Estimated December 04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | | | | | | | | | | |
| 1 | Substation Environmental Investigation, Remediation, and Pollution Prevention | (40,854) | 67,738 | 5,487 | 58,523 | 13,528 | 59,085 | 26,363 | 26,363 | 26,363 | 26,363 | 26,363 | 26,363 | 321,684 |
| 1a | Substation Environmental Investigation, Remediation, and Pollution Prevention - Costs included in Base Rates | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,084) | (2,083) | (2,084) | (2,083) | (2,084) | (2,084) | (25,000) |
| 2 | Distribution System Environmental Investigation, Remediation, and Pollution | 431,737 | 435,891 | 836,140 | 553,622 | 585,626 | 688,193 | 761,196 | 761,196 | 761,196 | 761,196 | 761,196 | 761,196 | 8,098,387 |
| 3a | Pipeline Integrity Management, Review/Update Plan and Risk Assessments | 0 | 0 | 0 | 0 | 0 | 0 | 165,000 | 165,000 | 165,000 | 165,000 | 165,000 | 165,000 | 990,000 |
| 4 | Above Ground Tank Secondary Containment | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | SO2 Emissions Allowances | 96,589 | 76,504 | 83,438 | 26,261 | 76,134 | 84,240 | 146,019 | 3,602,658 | 3,690,368 | 3,966,155 | 3,543,346 | 4,511,122 | 19,902,833 |
| 6 | 316(b) Clean Water Act | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | Total of O&M Activities | 485,389 | 578,050 | 922,982 | 636,322 | 673,206 | 829,435 | 1,096,494 | 4,553,134 | 4,640,843 | 4,916,631 | 4,493,821 | 5,461,597 | 29,287,905 |
| 3 | Recoverable Costs Allocated to Energy | 96,589 | 76,504 | 83,438 | 26,261 | 76,134 | 84,240 | 146,019 | 3,602,658 | 3,690,368 | 3,966,155 | 3,543,346 | 4,511,122 | 19,902,833 |
| 4 | Recoverable Costs Allocated to Demand - Transm | (42,937) | 65,655 | 3,404 | 56,440 | 11,445 | 57,002 | 24,279 | 24,280 | 24,279 | 24,280 | 24,279 | 24,279 | 296,684 |
| | Recoverable Costs Allocated to Demand - Distrib | 431,737 | 435,891 | 836,140 | 553,622 | 585,626 | 688,193 | 761,196 | 761,196 | 761,196 | 761,196 | 761,196 | 761,196 | 8,098,387 |
| | Recoverable Costs Allocated to Demand - Prod-Intm | 0 | 0 | 0 | 0 | 0 | 0 | 165,000 | 165,000 | 165,000 | 165,000 | 165,000 | 165,000 | 990,000 |
| 5 | Retail Energy Jurisdictional Factor | 0.97910 | 0.97440 | 0.97720 | 0.97450 | 0.97680 | 0.98090 | 0.95347 | 0.95027 | 0.94858 | 0.94678 | 0.94176 | 0.94781 | |
| 6 | Retail Transmission Demand Jurisdictional Factor | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | |
| | Retail Distribution Demand Jurisdictional Factor | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | |
| | Retail Production Demand Jurisdictional Factor - Intm | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | 94,570 | 74,545 | 81,536 | 25,591 | 74,368 | 82,631 | 139,225 | 3,423,496 | 3,500,609 | 3,755,076 | 3,336,982 | 4,275,687 | 18,864,318 |
| 8 | Jurisdictional Demand Recoverable Costs - Transm (B) | (30,964) | 47,347 | 2,455 | 40,702 | 8,254 | 41,107 | 17,509 | 17,509 | 17,509 | 17,509 | 17,509 | 17,509 | 213,955 |
| | Jurisdictional Demand Recoverable Costs - Distrib (B) | 429,704 | 433,838 | 832,202 | 551,014 | 582,868 | 684,952 | 757,611 | 757,611 | 757,611 | 757,611 | 757,611 | 757,611 | 8,060,244 |
| | Jurisdictional Demand Recoverable Costs - Prod-Intm (B) | 0 | 0 | 0 | 0 | 0 | 0 | 142,847 | 142,847 | 142,847 | 142,847 | 142,847 | 142,847 | 657,082 |
| 9 | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $493,310 | $555,730 | $916,193 | $617,307 | $665,490 | $808,690 | $1,057,192 | $4,341,465 | $4,418,576 | $4,673,043 | $4,254,949 | $5,193,654 | $27,995,599 |

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

Docket No. 040007-EI
Progress Energy Florida
Exhibit No. ____ (JP-2)
(Revised Sept. 3, 2004)
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**PROGRESS ENERGY FLORIDA**

Form 42 6E
0

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
**January 2004 to December 2004**

**Variance Report of Capital Investment Activities**
(In Dollars)

| Line | | (1) Estimated/ Actual | (2) Original Projection | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1 | Description of Capital Investment Activities | | | | |
| | 3b Pipeline Integrity Management - Bartow/Anclote Pipeline | 194,370 | 182,626 | 11,744 | 6% |
| | 4a Above Ground Tank Secondary Containment - Turner CT's | 73,945 | 99,408 | (25,463) | -26% |
| | 4b Above Ground Tank Secondary Containment - Bartow CT's | 28,317 | 18,535 | 9,782 | 53% |
| | 4c Above Ground Tank Secondary Containment - Crystal River 1 & 2 | 6,278 | 19,878 | (13,600) | -68% |
| | 5 SO2 Emissions Allowances - Deferred Gain | 500,891 | (227,424) | 728,315 | -320% |
| 2 | Total Capital Investment Activities - Recoverable Costs | 803,801 | 93,023 | 710,778 | 764% |
| 3 | Recoverable Costs Allocated to Energy | 500,891 | (227,424) | 728,315 | -320% |
| 4 | Recoverable Costs Allocated to Demand | 302,910 | 320,447 | (17,537) | -5% |

Notes:

Column (1) is the End of Period Totals on Form 42-7E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

**PROGRESS ENERGY FLORIDA**

Form 42-7E
0

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
**January 2004 to December 2004**

**Capital Investment Projects-Recoverable Costs**
(in Dollars)

| Line | Description | Actual January 04 | Actual February 04 | Actual March 04 | Actual April 04 | Actual May 04 | Actual June 04 | Estimated July 04 | Estimated August 04 | Estimated September 04 | Estimated October 04 | Estimated November 04 | Estimated December 04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects (A) | | | | | | | | | | | | | |
| 3b | Pipeline Integrity Management - Bartow/Anclote Pipeline | $9,024 | $15,577 | $16,037 | $16,124 | $16,245 | $16,324 | $16,530 | $16,921 | $17,311 | $17,702 | $18,092 | $18,483 | $194,370 |
| 4a | Above Ground Tank Secondary Containment - Turner CTs | 6,063 | 6,521 | 6,606 | 6,663 | 6,720 | 6,808 | 6,904 | 6,080 | 5,256 | 5,349 | 5,441 | 5,534 | 73,945 |
| 4b | Above Ground Tank Secondary Containment - Bartow CTs | 1,273 | 1,678 | 1,705 | 2,666 | 2,657 | 2,647 | 2,638 | 2,629 | 2,620 | 2,611 | 2,601 | 2,592 | 28,317 |
| 4c | Above Ground Tank Secondary Containment - Crystal River 1&2 | 365 | 367 | 563 | 561 | 559 | 557 | 556 | 554 | 552 | 550 | 548 | 546 | 6,278 |
| 5 | SO2 Emissions Allowances - Deferred Gain | (9,336) | (10,269) | 15,018 | 14,410 | (16,166) | (20,888) | 64,135 | 139,351 | 118,314 | 95,260 | 73,022 | 38,040 | 500,891 |
| 2 | Total Investment Projects - Recoverable Costs | 7,389 | 13,874 | 39,929 | 40,424 | 10,015 | 5,448 | 90,763 | 165,535 | 144,053 | 121,472 | 99,704 | 65,195 | 803,801 |
| 3 | Recoverable Costs Allocated to Energy | (9,336) | (10,269) | 15,018 | 14,410 | (16,166) | (20,888) | 64,135 | 139,351 | 118,314 | 95,260 | 73,022 | 38,040 | 500,891 |
| 4 | Recoverable Costs Allocated to Demand - Production - Base | 365 | 367 | 563 | 561 | 559 | 557 | 556 | 554 | 552 | 550 | 548 | 546 | 6,278 |
| | Recoverable Costs Allocated to Demand - Production - Intermediate | 9,024 | 15,577 | 16,037 | 16,124 | 16,245 | 16,324 | 16,530 | 16,921 | 17,311 | 17,702 | 18,092 | 18,483 | 194,370 |
| | Recoverable Costs Allocated to Demand - Production - Peaking | 7,336 | 8,199 | 8,311 | 9,329 | 9,377 | 9,455 | 9,542 | 8,709 | 7,876 | 7,960 | 8,042 | 8,126 | 102,262 |
| 5 | Retail Energy Jurisdictional Factor | 0.97910 | 0.97440 | 0.97720 | 0.97450 | 0.97680 | 0.98090 | 0.95347 | 0.95027 | 0.94858 | 0.94678 | 0.94176 | 0.94781 | |
| 6 | Retail Demand Jurisdictional Factor - Production - Base | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | |
| | Retail Demand Jurisdictional Factor - Production - Intermediate | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | |
| | Retail Demand Jurisdictional Factor - Production - Peaking | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | (9,141) | (10,006) | 14,676 | 14,042 | (15,791) | (20,489) | 61,151 | 132,421 | 112,230 | 90,190 | 68,769 | 36,054 | 474,108 |
| 8 | Jurisdictional Demand Recoverable Costs - Production - Base (C) | 350 | 352 | 540 | 538 | 536 | 534 | 534 | 532 | 530 | 528 | 526 | 524 | 6,024 |
| | Jurisdictional Demand Recoverable Costs - Production - Intermediate (C) | 7,812 | 13,486 | 13,884 | 13,959 | 14,064 | 14,132 | 14,311 | 14,649 | 14,987 | 15,325 | 15,663 | 16,001 | 168,274 |
| | Jurisdictional Demand Recoverable Costs - Production - Peaking (C) | 5,470 | 6,113 | 6,197 | 6,956 | 6,992 | 7,050 | 7,115 | 6,494 | 5,873 | 5,935 | 5,996 | 6,059 | 76,249 |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $4,491 | $9,945 | $35,297 | $35,496 | $5,801 | $1,228 | $83,110 | $154,095 | $133,619 | $111,979 | $90,954 | $58,639 | $724,654 |

Notes:

(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

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Progress Energy Florida
Exhibit No. ____ (JP-2)
(Revised Sept. 3, 2004)
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**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
**January 2004 to December 2004**

**Return on Capital Investments, Depreciation and Taxes**
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3b)
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Actual January 04 | Actual February 04 | Actual March 04 | Actual April 04 | Actual May 04 | Actual June 04 | Estimated July 04 | Estimated August 04 | Estimated September 04 | Estimated October 04 | Estimated November 04 | Estimated December 04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $ 1,104,029 | $ 76,669 | $ 6,238 | $ 9,410 | $ 12,330 | $ 2,000 | $35,177 | $35,177 | $35,177 | $35,177 | $35,177 | $35,177 | |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3 | Less: Accumulated Depreciation (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | CWIP - Non-Interest Bearing | 260,964 | 1,364,992 | 1,441,662 | 1,447,900 | 1,457,310 | 1,469,640 | 1,471,640 | 1,506,816 | 1,541,993 | 1,577,170 | 1,612,346 | 1,647,523 | 1,682,700 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $260,964 | 1,364,992 | 1,441,662 | 1,447,900 | 1,457,310 | 1,469,640 | 1,471,640 | 1,506,816 | 1,541,993 | 1,577,170 | 1,612,346 | 1,647,523 | 1,682,700 | |
| 6 | Average Net Investment | | 812,976 | 1,403,327 | 1,444,781 | 1,452,605 | 1,463,475 | 1,470,640 | 1,489,228 | 1,524,405 | 1,559,581 | 1,594,758 | 1,629,935 | 1,665,111 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) | 10.75% | 7,283 | 12,571 | 12,943 | 13,013 | 13,110 | 13,174 | 13,341 | 13,656 | 13,971 | 14,286 | 14,602 | 14,917 | $156,868 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) | 2.57% | 1,741 | 3,005 | 3,094 | 3,111 | 3,134 | 3,150 | 3,189 | 3,265 | 3,340 | 3,415 | 3,491 | 3,566 | 37,502 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (E) | 3.60% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 9,024 | 15,577 | 16,037 | 16,124 | 16,245 | 16,324 | 16,530 | 16,921 | 17,311 | 17,702 | 18,092 | 18,483 | 194,370 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 9,024 | 15,577 | 16,037 | 16,124 | 16,245 | 16,324 | 16,530 | 16,921 | 17,311 | 17,702 | 18,092 | 18,483 | 194,370 |
| 10 | Energy Jurisdictional Factor | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor - Production (Intermediate) | | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | |
| 12 | Retail Energy-Related Recoverable Costs (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (H) | | 7,812 | 13,486 | 13,884 | 13,959 | 14,064 | 14,132 | 14,311 | 14,649 | 14,987 | 15,325 | 15,663 | 16,001 | 168,274 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $7,812 | $13,486 | $13,884 | $13,959 | $14,064 | $14,132 | $14,311 | $14,649 | $14,987 | $15,325 | $15,663 | $16,001 | $168,274 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for Bartow/Anclote Pipeline project. None for this period.
(B) Applicable beginning of period and end of period depreciable base by Bartow/Anclote Pipeline.
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Bartow/Anclote Pipeline.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 3.60% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Description and reason for 'Other' adjustments to investment expenses for Bartow/Anclote Pipeline project. None for this period.
(G) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(H) Line 9b x Line 11
(I) Lines 2 + 3 x 89% @ .0183381 x 1/12 + 11% @ .0196598 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2002 Actual Property Tax Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

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Progress Energy Florida
Exhibit No. ____ (JP-2)
(Revised Sept. 3, 2004)
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**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
**January 2004 to December 2004**

**Return on Capital Investments, Depreciation and Taxes**
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4a)
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Actual January 04 | Actual February 04 | Actual March 04 | Actual April 04 | Actual May 04 | Actual June 04 | Estimated July 04 | Estimated August 04 | Estimated September 04 | Estimated October 04 | Estimated November 04 | Estimated December 04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $73,751 | $8,748 | $6,609 | $3,586 | $8,744 | $8,981 | $8,333 | ($156,747) | $8,333 | $8,333 | $8,333 | $8,333 | |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | 2 Plant-in-Service/Depreciation Base (B) | | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | 3 Less: Accumulated Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | 4 CWIP - Non-Interest Bearing | | 509,360 | 583,111 | 591,859 | 598,469 | 602,055 | 608,799 | 617,780 | 626,114 | 469,367 | 477,700 | 486,034 | 494,367 | 502,700 | |
| | 5 Net Investment (Lines 2 + 3 + 4) | | $509,360 | 583,111 | 591,859 | 598,469 | 602,055 | 608,799 | 617,780 | 626,114 | 469,367 | 477,700 | 486,034 | 494,367 | 502,700 | |
| | 6 Average Net Investment | | | 546,236 | 587,485 | 595,164 | 600,262 | 605,427 | 613,290 | 621,947 | 547,740 | 473,534 | 481,867 | 490,200 | 498,534 | |
| | 7 Return on Average Net Investment | | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) | 10.75% | | 4,893 | 5,263 | 5,332 | 5,377 | 5,424 | 5,494 | 5,572 | 4,907 | 4,242 | 4,317 | 4,391 | 4,466 | $59,676 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) | 2.57% | | 1,170 | 1,258 | 1,275 | 1,286 | 1,297 | 1,313 | 1,332 | 1,173 | 1,014 | 1,032 | 1,050 | 1,068 | 14,267 |
| | 8 Investment Expenses | | | | | | | | | | | | | | | |
| | e. Depreciation (E) | 4.80% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (I) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other (F) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 9 Total System Recoverable Expenses (Lines 7 + 8) | | | 6,063 | 6,521 | 6,606 | 6,663 | 6,720 | 6,808 | 6,904 | 6,080 | 5,256 | 5,349 | 5,441 | 5,534 | 73,945 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 6,063 | 6,521 | 6,606 | 6,663 | 6,720 | 6,808 | 6,904 | 6,080 | 5,256 | 5,349 | 5,441 | 5,534 | 73,945 |
| | 10 Energy Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| | 11 Demand Jurisdictional Factor - Production (Peaking) | | | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | |
| | 12 Retail Energy-Related Recoverable Costs (G) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 13 Retail Demand-Related Recoverable Costs (H) | | | 4,521 | 4,862 | 4,926 | 4,968 | 5,011 | 5,076 | 5,148 | 4,533 | 3,919 | 3,988 | 4,057 | 4,126 | 55,135 |
| | 14 Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $4,521 | $4,862 | $4,926 | $4,968 | $5,011 | $5,076 | $5,148 | $4,533 | $3,919 | $3,988 | $4,057 | $4,126 | $55,135 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for Above Ground Tank Secondary Containment - Turner CTs project. None for this period.
(B) Applicable beginning of period and end of period depreciable base by Above Ground Tank Secondary Containment - Turner CTs.
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Turner CTs.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 4.80% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Turner CTs project. None for this period.
(G) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(H) Line 9b x Line 11
(I) Lines 2 + 3 x .020912 x 1/12. Based on 2002 Actual Property Tax Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
**January 2004 to December 2004**

**Return on Capital Investments, Depreciation and Taxes**
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4b)
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Actual January 04 | Actual February 04 | Actual March 04 | Actual April 04 | Actual May 04 | Actual June 04 | Estimated July 04 | Estimated August 04 | Estimated September 04 | Estimated October 04 | Estimated November 04 | Estimated December 04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $68,291 | $4,629 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 153,698 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | | $0 | 0 | 0 | 0 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | |
| 3 | Less: Accumulated Depreciation (C) | | 0 | 0 | 0 | 0 | (730) | (1,460) | (2,190) | (2,920) | (3,650) | (4,380) | (5,110) | (5,841) | (6,571) | |
| 4 | CWIP - Non-Interest Bearing | | 80,575 | 148,866 | 153,495 | 153,698 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $80,575 | 148,866 | 153,495 | 153,698 | 152,968 | 152,238 | 151,508 | 150,778 | 150,048 | 149,318 | 148,588 | 147,857 | 147,127 | |
| 6 | Average Net Investment | | | 114,720 | 151,181 | 153,597 | 153,333 | 152,603 | 151,873 | 151,143 | 150,413 | 149,683 | 148,953 | 148,223 | 147,492 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) | 10.75% | | 1,028 | 1,354 | 1,376 | 1,374 | 1,367 | 1,361 | 1,354 | 1,347 | 1,341 | 1,334 | 1,328 | 1,321 | $15,885 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) | 2.57% | | 246 | 324 | 329 | 328 | 327 | 325 | 324 | 322 | 321 | 319 | 317 | 316 | 3,796 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (E) | 5.70% | | 0 | 0 | 0 | 730 | 730 | 730 | 730 | 730 | 730 | 730 | 730 | 730 | 6,571 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (I) | | | 0 | 0 | 0 | 234 | 233 | 232 | 230 | 229 | 228 | 227 | 226 | 225 | 2,064 |
| | e. Other (F) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | 1,273 | 1,678 | 1,705 | 2,666 | 2,657 | 2,647 | 2,638 | 2,629 | 2,620 | 2,611 | 2,601 | 2,592 | 28,317 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 1,273 | 1,678 | 1,705 | 2,666 | 2,657 | 2,647 | 2,638 | 2,629 | 2,620 | 2,811 | 2,601 | 2,592 | 28,317 |
| 10 | Energy Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor - Production (Peaking) | | | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | |
| 12 | Retail Energy-Related Recoverable Costs (G) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (H) | | | 949 | 1,251 | 1,271 | 1,988 | 1,981 | 1,974 | 1,967 | 1,960 | 1,954 | 1,947 | 1,939 | 1,933 | 21,114 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $949 | $1,251 | $1,271 | $1,988 | $1,981 | $1,974 | $1,967 | $1,960 | $1,954 | $1,947 | $1,939 | $1,933 | $21,114 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for Above Ground Tank Secondary Containment - Bartow CTs project. None for this period.
(B) Applicable beginning of period and and of period depreciable base by Above Ground Tank Secondary Containment - Bartow CTs.
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Bartow CTs.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 5.70% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Bartow CTs project. None for this period.
(G) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(H) Line 9b x Line 11
(I) Lines 2 + 3 x .018338 x 1/12. Based on 2002 Actual Property Tax Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
**January 2004 to December 2004**

**Return on Capital Investments, Depreciation and Taxes**
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4c)
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Actual January 04 | Actual February 04 | Actual March 04 | Actual April 04 | Actual May 04 | Actual June 04 | Estimated July 04 | Estimated August 04 | Estimated September 04 | Estimated October 04 | Estimated November 04 | Estimated December 04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $373 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| | b. Clearings to Plant | | | 0 | 0 | 33,092 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | | $0 | 0 | 0 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | |
| 3 | Less: Accumulated Depreciation (C) | | 0 | 0 | 0 | (146) | (292) | (438) | (585) | (731) | (877) | (1,023) | (1,169) | (1,315) | (1,462) | |
| 4 | CWIP - Non-Interest Bearing | | 32,719 | 33,092 | 33,092 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $32,719 | 33,092 | 33,092 | 32,946 | 32,800 | 32,654 | 32,508 | 32,361 | 32,215 | 32,069 | 31,923 | 31,777 | 31,630 | |
| 6 | Average Net Investment | | | 32,906 | 33,092 | 33,019 | 32,873 | 32,727 | 32,581 | 32,434 | 32,288 | 32,142 | 31,996 | 31,850 | 31,704 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) | 10.75% | | 295 | 296 | 296 | 294 | 293 | 292 | 291 | 289 | 288 | 287 | 285 | 284 | $3,490 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) | 2.57% | | 70 | 71 | 71 | 70 | 70 | 70 | 69 | 69 | 69 | 69 | 68 | 68 | 834 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (E) | 5.30% | | 0 | 0 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 1,462 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (I) | | | 0 | 0 | 50 | 50 | 50 | 50 | 49 | 49 | 49 | 49 | 49 | 48 | 493 |
| | e. Other (F) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | 365 | 367 | 563 | 561 | 559 | 557 | 556 | 554 | 552 | 550 | 548 | 546 | 6,278 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 365 | 367 | 563 | 561 | 559 | 557 | 556 | 554 | 552 | 550 | 548 | 546 | 6,278 |
| 10 | Energy Jurisdictional Factor | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 11 | Demand Jurisdictional Factor - Production (Base) | | | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | |
| 12 | Retail Energy-Related Recoverable Costs (G) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (H) | | | 350 | 352 | 540 | 538 | 536 | 534 | 534 | 532 | 530 | 528 | 526 | 524 | 6,024 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $350 | $352 | $540 | $538 | $536 | $534 | $534 | $532 | $530 | $528 | $526 | $524 | $6,024 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for Above Ground Tank Secondary Containment - Crystal River 1&2 project. None for this period.
(B) Applicable beginning of period and end of period depreciable base by Above Ground Tank Secondary Containment - Crystal River 1&2.
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Crystal River 1&2.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 5.30% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Crystal River 1&2 project. None for this period.
(G) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(H) Line 9b x Line 11
(I) Lines 2 + 3 x .018338 x 1/12. Based on 2002 Actual Property Tax Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
**January 2004 to December 2004**

**Schedule of Amortization and Return**
Deferred Gain on Sales of Emissions Allowances
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Actual January 04 | Actual February 04 | Actual March 04 | Actual April 04 | Actual May 04 | Actual June 04 | Estimated July 04 | Estimated August 04 | Estimated September 04 | Estimated October 04 | Estimated November 04 | Estimated December 04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 1581001 SO2 Emission Allowance Inventory | | $ 912,089 | $820,501 | $743,997 | $5,376,809 | $634,298 | $558,164 | $473,924 | $15,877,605 | $14,026,271 | $12,087,229 | $9,872,399 | $8,080,377 | $3,569,255 | 3,569,255 |
| | b. 25401FL Auctioned SO2 Allowance | | (1,707,393) | (1,707,393) | (1,707,393) | (1,707,393) | (1,707,393) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,621) |
| 2 | Total Working Capital | | $ (795,304) | ($886,893) | ($963,396) | $3,669,416 | ($1,073,095) | ($1,839,657) | ($1,923,897) | $13,479,784 | $11,628,450 | $9,689,408 | $7,474,578 | $5,682,556 | $1,171,434 | $1,171,434 |
| 3 | Average Net Investment | | | (841,098) | (925,144) | 1,353,010 | 1,298,160 | (1,456,376) | (1,881,777) | 5,777,944 | 12,554,117 | 10,658,929 | 8,581,993 | 6,578,567 | 3,426,995 | |
| 4 | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (A) | 10.75% | | (7,535) | (8,288) | 12,121 | 11,629 | (13,047) | (16,858) | 51,761 | 112,464 | 95,486 | 76,880 | 58,933 | 30,700 | $404,248 |
| | b. Debt Component (Line 3 x 2.57% x 1/12) | 2.57% | | (1,801) | (1,981) | 2,898 | 2,780 | (3,119) | (4,030) | 12,374 | 26,887 | 22,828 | 18,380 | 14,089 | 7,339 | 96,643 |
| 5 | Total Return Component (D) | | | (9,336) | (10,269) | 15,018 | 14,410 | (16,166) | (20,888) | 64,135 | 139,351 | 118,314 | 95,260 | 73,022 | 38,040 | 500,891 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 5090001 SO2 allowance expense | | | 96,589 | 76,504 | 83,438 | 26,261 | 76,134 | 84,240 | 146,019 | 3,602,858 | 3,690,368 | 3,966,155 | 3,543,346 | 4,511,122 | 19,902,833 |
| 7 | Net Expense (E) | | | 96,589 | 76,504 | 83,438 | 26,261 | 76,134 | 84,240 | 146,019 | 3,602,858 | 3,690,368 | 3,966,155 | 3,543,346 | 4,511,122 | 19,902,833 |
| 8 | Total System Recoverable Expenses (Lines 5 + 7) | | | 87,253 | 66,235 | 98,456 | 40,670 | 59,968 | 63,353 | 210,154 | 3,742,009 | 3,808,882 | 4,061,415 | 3,616,368 | 4,549,162 | 20,403,725 |
| | a. Recoverable costs allocated to Energy | | | 87,253 | 66,235 | 98,456 | 40,670 | 59,968 | 63,353 | 210,154 | 3,742,009 | 3,808,882 | 4,061,415 | 3,616,368 | 4,549,162 | 20,403,725 |
| | b. Recoverable costs allocated to Demand | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Energy Jurisdictional Factor | | | 0.97910 | 0.97440 | 0.97720 | 0.97450 | 0.97680 | 0.98090 | 0.95347 | 0.95027 | 0.94858 | 0.94678 | 0.94176 | 0.94781 | |
| 10 | Demand Jurisdictional Factor | | | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | |
| 11 | Retail Energy-Related Recoverable Costs (B) | | | 85,429 | 64,539 | 96,212 | 39,633 | 58,577 | 62,143 | 200,376 | 3,555,919 | 3,612,840 | 3,845,267 | 3,405,751 | 4,311,741 | 19,338,425 |
| 12 | Retail Demand-Related Recoverable Costs (C) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | | $ 85,429 | $ 64,539 | $ 96,212 | $ 39,633 | $ 58,577 | $ 62,143 | $ 200,376 | $ 3,555,919 | $ 3,612,840 | $ 3,845,267 | $ 3,405,751 | $ 4,311,741 | $ 19,338,425 |

Notes:
(A) Line 3 x 10.7500% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

EXHIBIT No. __ (JP-3)

**ENVIRONMENTAL COST RECOVERY**
COMMISSION FORMS 42-1P THROUGH 42-7P

CALCULATION OF PROJECTED PERIOD AMOUNT
JANUARY 2005 - DECEMBER 2005

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI EXHIBIT NO. 10
COMPANY/ Progress
WITNESS: Javier Portuondo
DATE 11-08-04

**PROGRESS ENERGY FLORIDA**

Form 42-1P

Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
**JANUARY 2005 - DECEMBER 2005**

| Line | | Energy ($) | Transmission Demand ($) | Distribution Demand ($) | Production Demand ($) | Total ($) |
|---|---|---|---|---|---|---|
| 1 | Total Jurisdictional Rev. Req. for the projected period | | | | | |
| | a Projected O&M Activities (Form 42-2P, Lines 7 through 9) | $20,306,133 | $811,112 | $7,320,107 | $1,163,688 | $29,601,039 |
| | b Projected Capital Projects (Form 42-3P, Lines 7 through 9) | 451,579 | 0 | 0 | 451,831 | 903,410 |
| | c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b) | $20,757,712 | $811,112 | $7,320,107 | $1,615,519 | $30,504,449 |
| 2 | True-up for Estimated Over/(Under) Recovery for the current period January 2004 - December 2004 (Form 42-2E, Line 5 + 6 + 10) | (12,821,172) | (145,415) | (5,478,161) | (582,518) | ($19,027,266) |
| 3 | Final True-up for the period January 2003 - December 2003 (Form 42-1A, Line 3) | 0 | 26,513 | 924,924 | 0 | $951,437 |
| 4 | Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection period January 2005 - December 2005 (Line 1 - Line 2 - Line 3) | $33,578,884 | $930,014 | $11,873,344 | $2,198,036 | $48,580,278 |
| 5 | Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072) | $33,603,061 | $930,683 | $11,881,893 | $2,199,619 | $48,615,256 |

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Progress Energy Florida
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**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**JANUARY 2005 - DECEMBER 2005**

Form 42-2P

O&M Activities
(In Dollars)

| Line | | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of O&M Activities | | | | | | | | | | | | | | | |
| 1 | Substation Environmental Investigation, Remediation, and Pollution Prevention | 95,481 | 95,481 | 95,481 | 95,581 | 95,581 | 95,581 | 97,117 | 95,581 | 95,581 | 95,581 | 95,581 | 97,121 | 1,149,748 | 1,149,748 | 0 |
| 1a | Substation Environmental Investigation, Remediation, and Pollution Prevention - Costs Included in Base Rates | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (2,083) | (25,000) | (25,000) | 0 |
| 2 | Distribution System Environmental Investigation, Remediation, and Pollution Prevention | 612,565 | 612,565 | 612,565 | 612,664 | 612,664 | 612,664 | 614,200 | 612,664 | 612,664 | 612,664 | 612,664 | 614,204 | 7,354,748 | 7,354,748 | 0 |
| 3a | Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm | 102,833 | 111,333 | 122,333 | 103,833 | 105,133 | 185,633 | 156,133 | 79,633 | 24,633 | 20,833 | 20,833 | 20,833 | 1,056,000 | 1,056,000 | 0 |
| 4 | Above Ground Tank Secondary Containment | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | $SO_2$ Emissions Allowances | 377,083 | 351,708 | 366,303 | 665,161 | 1,106,012 | 1,498,833 | 1,995,981 | 2,440,504 | 2,704,318 | 3,038,742 | 3,479,211 | 3,411,290 | 21,435,145 | 0 | 21,435,145 |
| 6 | Phase II Cooling Water Intake - Base | 4,270 | 3,745 | 3,745 | 4,270 | 3,745 | 3,745 | 4,270 | 3,745 | 3,745 | 4,270 | 3,745 | 3,737 | 47,032 | 47,032 | 0 |
| | Phase II Cooling Water Intake - Intm | 46,484 | 45,959 | 45,959 | 46,484 | 45,959 | 45,959 | 46,484 | 45,959 | 45,959 | 46,484 | 45,959 | 45,951 | 553,600 | 553,600 | 0 |
| 6a | Phase II Cooling Water Intake - Base Costs Included in Base Rates | (23,125) | (23,125) | (23,125) | (23,125) | (23,125) | (23,125) | (23,125) | (23,125) | (23,125) | (23,125) | (23,125) | (23,125) | (277,500) | (277,500) | 0 |
| | Phase II Cooling Water Intake - Intm Costs Included in Base Rates | (833) | (833) | (833) | (833) | (833) | (833) | (833) | (833) | (833) | (833) | (833) | (833) | (10,000) | (10,000) | 0 |
| 2 | Total of O&M Activities | 1,212,675 | 1,194,746 | 1,222,345 | 1,501,971 | 1,943,053 | 2,414,373 | 2,890,124 | 3,252,045 | 3,460,859 | 3,792,533 | 4,231,952 | 4,167,095 | 31,283,773 | $9,848,627 | $21,435,145 |
| 3 | Recoverable Costs Allocated to Energy | 377,083 | 351,708 | 366,303 | 665,181 | 1,106,012 | 1,498,833 | 1,995,981 | 2,440,504 | 2,704,318 | 3,038,742 | 3,479,211 | 3,411,290 | 21,435,149 | | |
| 4 | Recoverable Costs Allocated to Demand - Transm | 93,398 | 93,398 | 93,398 | 93,497 | 93,497 | 93,497 | 95,034 | 93,497 | 93,497 | 93,497 | 93,497 | 95,038 | 1,124,748 | | |
| | Recoverable Costs Allocated to Demand - Distrib | 612,565 | 612,565 | 612,565 | 612,664 | 612,664 | 612,664 | 614,200 | 612,664 | 612,664 | 612,664 | 612,664 | 614,204 | 7,354,748 | | |
| | Recoverable Costs Allocated to Demand - Prod-Base | (18,855) | (19,380) | (19,380) | (18,855) | (19,380) | (19,380) | (18,855) | (19,380) | (19,380) | (18,855) | (19,380) | (19,388) | (230,468) | | |
| | Recoverable Costs Allocated to Demand - Prod-Intm | 148,484 | 156,459 | 167,459 | 149,484 | 150,259 | 230,759 | 203,784 | 124,759 | 69,759 | 66,484 | 65,959 | 65,951 | 1,599,600 | | |
| | Recoverable Costs Allocated to Demand - Prod-Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.94678 | 0.94985 | 0.94437 | 0.94463 | 0.94488 | 0.95025 | 0.95308 | 0.95225 | 0.94974 | 0.94683 | 0.94053 | 0.94609 | | | |
| 6 | Retail Transmission Demand Jurisdictional Factor | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | 0.72115 | | | |
| | Retail Distribution Demand Jurisdictional Factor | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | 0.99529 | | | |
| | Retail Production Demand Jurisdictional Factor - Base | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | | | |
| | Retail Production Demand Jurisdictional Factor - Intm | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | | | |
| | Retail Production Demand Jurisdictional Factor - Peaking | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | 357,015 | 333,997 | 347,815 | 628,350 | 1,045,049 | 1,422,365 | 1,902,310 | 2,323,970 | 2,566,399 | 2,877,172 | 3,272,303 | 3,227,387 | 20,306,133 | | |
| 8 | Jurisdictional Demand Recoverable Costs - Transm (B) | 67,354 | 67,354 | 67,354 | 67,426 | 67,426 | 67,426 | 68,534 | 67,426 | 67,426 | 67,426 | 67,426 | 68,536 | 811,112 | | |
| | Jurisdictional Demand Recoverable Costs - Distrib (B) | 609,680 | 609,680 | 609,680 | 609,778 | 609,778 | 609,778 | 611,307 | 609,778 | 609,778 | 609,778 | 609,778 | 611,311 | 7,320,107 | | |
| | Jurisdictional Demand Recoverable Costs - Prod-Base (B) | (18,093) | (18,596) | (18,596) | (18,093) | (18,596) | (18,596) | (18,093) | (18,596) | (18,596) | (18,093) | (18,596) | (18,604) | (221,150) | | |
| | Jurisdictional Demand Recoverable Costs - Prod-Intm (B) | 128,549 | 135,453 | 144,978 | 129,414 | 130,085 | 199,777 | 176,424 | 108,009 | 60,393 | 57,558 | 57,103 | 57,096 | 1,384,838 | | |
| | Jurisdictional Demand Recoverable Costs - Prod-Peaking (B) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| 9 | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $1,144,504 | $1,127,888 | $1,151,228 | $1,416,676 | $1,833,742 | $2,280,750 | $2,740,483 | $3,090,587 | $3,287,400 | $3,593,842 | $3,988,014 | $3,945,727 | $29,601,039 | | |

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

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**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**JANUARY 2005 - DECEMBER 2005**

Form 42-3P

Capital Investment Projects-Recoverable Costs
(In Dollars)

| Line | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 Description of Investment Projects (A) | | | | | | | | | | | | | | | |
| 3b Pipeline Integrity Management - Bartow/Anclote Pipeline-Intm | 26,687 | 26,622 | 26,557 | 26,492 | 26,427 | 26,362 | 26,297 | 26,232 | 26,167 | 26,102 | 26,037 | 25,971 | 315,953 | $315,953 | $0 |
| 4a Above Ground Tank Secondary Containment - Turner CTs-Pkg | 8,467 | 8,441 | 8,415 | 8,390 | 8,364 | 8,338 | 8,312 | 8,286 | 8,260 | 8,234 | 8,208 | 8,182 | 99,897 | 99,897 | 0 |
| 4b Above Ground Tank Secondary Containment - Bartow CTs-Pkg | 2,645 | 2,636 | 2,626 | 2,617 | 2,607 | 2,597 | 2,588 | 2,578 | 2,569 | 2,559 | 2,550 | 2,540 | 31,112 | 31,112 | 0 |
| 4c Above Ground Tank Secondary Containment - Crystal River 1&2-Base | 542 | 540 | 539 | 537 | 535 | 533 | 531 | 529 | 528 | 526 | 524 | 522 | 6,386 | 6,386 | 0 |
| 4d Above Ground Tank Secondary Containment - Intercession City CTs-Pkg | 694 | 2,081 | 3,469 | 4,856 | 6,244 | 7,631 | 9,019 | 10,406 | 11,794 | 13,181 | 14,569 | 15,956 | 99,900 | 99,900 | 0 |
| 5 $SO_2$ Emissions Allowances - Deferred Gain | 10,910 | 6,865 | 15,203 | 34,133 | 46,970 | 59,191 | 64,473 | 64,517 | 60,630 | 53,422 | 41,914 | 16,005 | 476,234 | 0 | 476,234 |
| 2 Total Investment Projects - Recoverable Costs | 49,945 | 47,185 | 56,809 | 77,025 | 93,147 | 104,652 | 111,220 | 112,548 | 109,948 | 104,024 | 93,802 | 69,176 | 1,029,482 | $553,248 | $476,234 |
| 3 Recoverable Costs Allocated to Energy | 10,910 | 6,865 | 15,203 | 34,133 | 46,970 | 59,191 | 64,473 | 64,517 | 60,630 | 53,422 | 41,914 | 16,005 | 476,234 | | |
| 4 Recoverable Costs Allocated to Demand - Production - Base | 542 | 540 | 539 | 537 | 535 | 533 | 531 | 529 | 528 | 526 | 524 | 522 | 6,386 | | |
| Recoverable Costs Allocated to Demand - Production - Intermediate | 26,687 | 26,622 | 26,557 | 26,492 | 26,427 | 26,362 | 26,297 | 26,232 | 26,167 | 26,102 | 26,037 | 25,971 | 315,953 | | |
| Recoverable Costs Allocated to Demand - Production - Peaking | 11,806 | 13,158 | 14,510 | 15,863 | 17,215 | 18,566 | 19,919 | 21,270 | 22,623 | 23,974 | 25,327 | 26,678 | 230,909 | | |
| 5 Retail Energy Jurisdictional Factor | 0.94678 | 0.94985 | 0.94437 | 0.94483 | 0.94488 | 0.95025 | 0.95308 | 0.95225 | 0.94974 | 0.94683 | 0.94053 | 0.94609 | | | |
| 6 Retail Demand Jurisdictional Factor - Production - Base | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | | | |
| Retail Demand Jurisdictional Factor - Production - Intermediate | 0.88574 | 0.88574 | 0.88574 | 0.88574 | 0.88574 | 0.88574 | 0.88574 | 0.88574 | 0.88574 | 0.88574 | 0.88574 | 0.88574 | | | |
| Retail Demand Jurisdictional Factor - Production - Peaking | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | | | |
| 7 Jurisdictional Energy Recoverable Costs (B) | 10,329 | 6,520 | 14,357 | 32,243 | 46,271 | 56,248 | 61,447 | 61,436 | 57,582 | 50,582 | 39,422 | 15,143 | 451,579 | | |
| 8 Jurisdictional Demand Recoverable Costs - Production - Base (C) | 520 | 518 | 517 | 515 | 513 | 511 | 510 | 508 | 507 | 505 | 503 | 501 | 6,128 | | |
| Jurisdictional Demand Recoverable Costs - Production - Intermediate (C) | 23,104 | 23,048 | 22,991 | 22,935 | 22,879 | 22,823 | 22,766 | 22,710 | 22,654 | 22,598 | 22,541 | 22,484 | 273,533 | | |
| Jurisdictional Demand Recoverable Costs - Production - Peaking (C) | 8,803 | 9,811 | 10,819 | 11,828 | 12,836 | 13,843 | 14,852 | 15,859 | 16,868 | 17,875 | 18,884 | 19,892 | 172,170 | | |
| 9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $42,756 | $39,896 | $48,685 | $67,522 | $82,499 | $93,423 | $99,575 | $100,513 | $97,611 | $91,560 | $81,350 | $58,019 | $903,410 | | |

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

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Progress Energy Florida
Exhibit No. ____ (JP-3)
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**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**JANUARY 2005 - DECEMBER 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3b)
(In Dollars)

| Line | Description | | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 1,682,700 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | | $0 | 1,682,700 | 1,682,700 | 1,682,700 | 1,682,700 | 1,682,700 | 1,682,700 | 1,682,700 | 1,682,700 | 1,682,700 | 1,682,700 | 1,682,700 | 1,682,700 | |
| 3 | Less: Accumulated Depreciation (C) | | 0 | (5,048) | (10,096) | (15,144) | (20,192) | (25,241) | (30,289) | (35,337) | (40,385) | (45,433) | (50,481) | (55,529) | (60,577) | |
| 4 | CWIP - Non-Interest Bearing | | 1,682,700 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $1,682,700 | 1,677,652 | 1,672,604 | 1,667,556 | 1,662,508 | 1,657,460 | 1,652,411 | 1,647,363 | 1,642,315 | 1,637,267 | 1,632,219 | 1,627,171 | 1,622,123 | |
| 6 | Average Net Investment | | | 1,680,176 | 1,675,128 | 1,670,080 | 1,665,032 | 1,659,984 | 1,654,935 | 1,649,887 | 1,644,839 | 1,639,791 | 1,634,743 | 1,629,695 | 1,624,647 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) | 10.75% | | 15,052 | 15,006 | 14,961 | 14,916 | 14,871 | 14,825 | 14,780 | 14,735 | 14,690 | 14,645 | 14,599 | 14,554 | $177,634 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) | 2.57% | | 3,598 | 3,588 | 3,577 | 3,566 | 3,555 | 3,544 | 3,534 | 3,523 | 3,512 | 3,501 | 3,490 | 3,479 | 42,467 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (E) | 3.60% | | 5,048 | 5,048 | 5,048 | 5,048 | 5,048 | 5,048 | 5,048 | 5,048 | 5,048 | 5,048 | 5,048 | 5,048 | 60,577 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (I) | | | 2,989 | 2,980 | 2,971 | 2,962 | 2,953 | 2,944 | 2,935 | 2,926 | 2,917 | 2,908 | 2,899 | 2,890 | 35,271 |
| | e. Other (F) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | 26,687 | 26,622 | 26,557 | 26,492 | 26,427 | 26,362 | 26,297 | 26,232 | 26,167 | 26,102 | 26,037 | 25,971 | 315,949 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 26,687 | 26,622 | 26,557 | 26,492 | 26,427 | 26,362 | 26,297 | 26,232 | 26,167 | 26,102 | 26,037 | 25,971 | 315,953 |
| 10 | Energy Jurisdictional Factor | | | 0.94676 | 0.94965 | 0.94437 | 0.94463 | 0.94488 | 0.95025 | 0.95308 | 0.95225 | 0.94974 | 0.94683 | 0.94053 | 0.94609 | |
| 11 | Demand Jurisdictional Factor - Production (Intermediate) | | | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | 0.86574 | |
| 12 | Retail Energy-Related Recoverable Costs (G) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (H) | | | 23,104 | 23,046 | 22,991 | 22,935 | 22,879 | 22,823 | 22,768 | 22,710 | 22,654 | 22,598 | 22,541 | 22,484 | 273,533 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $ 23,104 | $ 23,046 | $ 22,991 | $ 22,935 | $ 22,879 | $ 22,823 | $ 22,768 | $ 22,710 | $ 22,654 | $ 22,598 | $ 22,541 | $ 22,484 | $ 273,533 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for Bartow/Anclote Pipeline project. None for this period.
(B) Applicable beginning of period and end of period depreciable base by Bartow/Anclote Pipeline.
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Bartow/Anclote Pipeline.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, weighted cost of equity component of capital structure of 6.81%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 3.60% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Description and reason for 'Other' adjustments to investment expenses for Bartow/Anclote Pipeline project. None for this period.
(G) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(H) Line 9b x Line 11
(I) Lines 2 + 3 x 89% @ .021659 x 1/12 + 11% @ .0191036 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2003 Actual Property Tax Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

Docket No. 040007-EI
Progress Energy Florida
Exhibit No. ___ (JP-3)
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**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**JANUARY 2005 - DECEMBER 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4a)
(In Dollars)

| Line | Description | | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 502,700 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | | $0 | 502,700 | 502,700 | 502,700 | 502,700 | 502,700 | 502,700 | 502,700 | 502,700 | 502,700 | 502,700 | 502,700 | 502,700 | |
| 3 | Less: Accumulated Depreciation (C) | | 0 | (2,011) | (4,022) | (6,032) | (8,043) | (10,054) | (12,065) | (14,076) | (16,086) | (18,097) | (20,108) | (22,119) | (24,130) | |
| 4 | CWIP - Non-Interest Bearing | | 502,700 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $502,700 | 500,689 | 498,678 | 496,668 | 494,657 | 492,646 | 490,635 | 488,624 | 486,614 | 484,603 | 482,592 | 480,581 | 478,570 | |
| 6 | Average Net Investment | | | 501,695 | 499,684 | 497,673 | 495,662 | 493,651 | 491,641 | 489,630 | 487,619 | 485,608 | 483,597 | 481,587 | 479,576 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) | 10.75% | | 4,494 | 4,476 | 4,458 | 4,440 | 4,422 | 4,404 | 4,386 | 4,368 | 4,350 | 4,332 | 4,314 | 4,296 | $52,743 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) | 2.57% | | 1,074 | 1,070 | 1,066 | 1,062 | 1,057 | 1,053 | 1,049 | 1,044 | 1,040 | 1,036 | 1,031 | 1,027 | 12,609 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (E) | 4.80% | | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 2,011 | 24,130 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (I) | | | 886 | 884 | 880 | 877 | 873 | 870 | 866 | 863 | 859 | 856 | 852 | 848 | 10,416 |
| | e. Other (F) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | 8,467 | 8,441 | 8,415 | 8,390 | 8,364 | 8,338 | 8,312 | 8,286 | 8,260 | 8,234 | 8,208 | 8,182 | 99,898 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 8,467 | 8,441 | 8,415 | 8,390 | 8,364 | 8,338 | 8,312 | 8,286 | 8,260 | 8,234 | 8,208 | 8,182 | 99,897 |
| 10 | Energy Jurisdictional Factor | | | 0.94678 | 0.94985 | 0.94437 | 0.94463 | 0.94488 | 0.95025 | 0.95308 | 0.95225 | 0.94974 | 0.94683 | 0.94053 | 0.94609 | |
| 11 | Demand Jurisdictional Factor - Production (Peaking) | | | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | |
| 12 | Retail Energy-Related Recoverable Costs (G) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (H) | | | 6,313 | 6,294 | 6,274 | 6,256 | 6,236 | 6,217 | 6,198 | 6,178 | 6,159 | 6,139 | 6,120 | 6,101 | 74,485 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $ 6,313 | $ 6,294 | $ 6,274 | $ 6,256 | $ 6,236 | $ 6,217 | $ 6,198 | $ 6,178 | $ 6,159 | $ 6,139 | $ 6,120 | $ 6,101 | $ 74,485 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for Above Ground Tank Secondary Containment - Turner CTs project. None for this period.
(B) Applicable beginning of period and end of period depreciable base by Above Ground Tank Secondary Containment - Turner CTs.
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Turner CTs.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, weighted cost of equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 4.80% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Turner CTs project. None for this period.
(G) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(H) Line 9b x Line 11
(I) Lines 2 + 3 x .0212735 x 1/12. Based on 2003 Actual Property Tax Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**JANUARY 2005 - DECEMBER 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4b)
**(in Dollars)**

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | $153,698 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | 153,698 | |
| 3 | Less: Accumulated Depreciation (C) | (6,571) | (7,301) | (8,031) | (8,761) | (9,491) | (10,221) | (10,951) | (11,681) | (12,412) | (13,142) | (13,872) | (14,602) | (15,332) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $147,127 | 146,397 | 145,667 | 144,937 | 144,207 | 143,477 | 142,747 | 142,017 | 141,286 | 140,556 | 139,826 | 139,096 | 138,366 | |
| 6 | Average Net Investment | | 146,762 | 146,032 | 145,302 | 144,572 | 143,842 | 143,112 | 142,382 | 141,652 | 140,921 | 140,191 | 139,461 | 138,731 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) 10.75% | | 1,315 | 1,308 | 1,302 | 1,295 | 1,289 | 1,282 | 1,276 | 1,269 | 1,262 | 1,256 | 1,249 | 1,243 | $15,345 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) 2.57% | | 314 | 313 | 311 | 310 | 308 | 306 | 305 | 303 | 302 | 300 | 299 | 297 | 3,689 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (E) 5.70% | | 730 | 730 | 730 | 730 | 730 | 730 | 730 | 730 | 730 | 730 | 730 | 730 | 8,761 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (I) | | 286 | 285 | 283 | 282 | 280 | 279 | 277 | 276 | 275 | 273 | 272 | 270 | 3,338 |
| | e. Other (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 2,645 | 2,636 | 2,626 | 2,617 | 2,607 | 2,597 | 2,588 | 2,578 | 2,569 | 2,559 | 2,550 | 2,540 | 31,113 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 2,645 | 2,636 | 2,626 | 2,617 | 2,607 | 2,597 | 2,588 | 2,578 | 2,569 | 2,559 | 2,550 | 2,540 | 31,112 |
| 10 | Energy Jurisdictional Factor | | 0.94678 | 0.94985 | 0.94437 | 0.94463 | 0.94488 | 0.95025 | 0.95308 | 0.95225 | 0.94974 | 0.94683 | 0.94053 | 0.94609 | |
| 11 | Demand Jurisdictional Factor - Production (Peaking) | | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | |
| 12 | Retail Energy-Related Recoverable Costs (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (H) | | 1,972 | 1,965 | 1,958 | 1,951 | 1,944 | 1,936 | 1,930 | 1,922 | 1,915 | 1,908 | 1,901 | 1,894 | 23,198 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $ 1,972 | $ 1,965 | $ 1,958 | $ 1,951 | $ 1,944 | $ 1,936 | $ 1,930 | $ 1,922 | $ 1,915 | $ 1,908 | $ 1,901 | $ 1,894 | $ 23,198 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for Above Ground Tank Secondary Containment - Bartow CTs project. None for this period.
(B) Applicable beginning of period and end of period depreciable base by Above Ground Tank Secondary Containment - Bartow CTs.
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Bartow CTs.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, weighted cost of equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 5.70% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Bartow CTs project. None for this period.
(G) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(H) Line 9b x Line 11
(I) Lines 2 + 3 x .023445 x 1/12. Based on 2003 Actual Property Tax Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

Docket No. 040007-EI
Progress Energy Florida
Exhibit No. ____ (JP-3)
Page 7 of 18

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**JANUARY 2005 - DECEMBER 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4c)
(In Dollars)

| Line | Description | | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | | $33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | 33,092 | |
| 3 | Less: Accumulated Depreciation (C) | | (1,462) | (1,608) | (1,754) | (1,900) | (2,047) | (2,193) | (2,339) | (2,485) | (2,631) | (2,777) | (2,924) | (3,070) | (3,216) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $31,630 | 31,484 | 31,338 | 31,192 | 31,045 | 30,899 | 30,753 | 30,607 | 30,461 | 30,315 | 30,168 | 30,022 | 29,876 | |
| 6 | Average Net Investment | | | 31,557 | 31,411 | 31,265 | 31,118 | 30,972 | 30,826 | 30,680 | 30,534 | 30,388 | 30,242 | 30,095 | 29,949 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) | 10.75% | | 283 | 281 | 280 | 279 | 277 | 276 | 275 | 274 | 272 | 271 | 270 | 268 | $3,306 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) | 2.57% | | 68 | 67 | 67 | 67 | 66 | 66 | 66 | 65 | 65 | 65 | 64 | 64 | 790 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (E) | 5.30% | | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 1,754 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (I) | | | 46 | 46 | 45 | 45 | 45 | 45 | 44 | 44 | 44 | 44 | 44 | 43 | 535 |
| | e. Other (F) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | 542 | 540 | 539 | 537 | 535 | 533 | 531 | 529 | 528 | 526 | 524 | 522 | 6,385 |
| | a. Recoverable Costs Allocated to Energy | | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | b. Recoverable Costs Allocated to Demand | | | 542 | 540 | 539 | 537 | 535 | 533 | 531 | 529 | 528 | 526 | 524 | 522 | 6,386 |
| 10 | Energy Jurisdictional Factor | | | 0.94678 | 0.94965 | 0.94437 | 0.94463 | 0.94486 | 0.95025 | 0.95308 | 0.95225 | 0.94974 | 0.94683 | 0.94053 | 0.94609 | |
| 11 | Demand Jurisdictional Factor - Production (Base) | | | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | 0.95957 | |
| 12 | Retail Energy-Related Recoverable Costs (G) | | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 13 | Retail Demand-Related Recoverable Costs (H) | | | 520 | 518 | 517 | 515 | 513 | 511 | 510 | 508 | 507 | 505 | 503 | 501 | 6,128 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $ 520 | $ 518 | $ 517 | $ 515 | $ 513 | $ 511 | $ 510 | $ 508 | $ 507 | $ 505 | $ 503 | $ 501 | $ 6,128 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for Above Ground Tank Secondary Containment - Crystal River 1&2 project. None for this period.
(B) Applicable beginning of period and end of period depreciable base by Above Ground Tank Secondary Containment - Crystal River 1&2.
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Crystal River 1&2.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, weighted cost of equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 5.30% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Crystal River 1&2 project. None for this period.
(G) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(H) Line 9b x Line 11
(I) Lines 2 + 3 x .017436 x 1/12. Based on 2003 Actual Property Tax Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**JANUARY 2005 - DECEMBER 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4d)
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | | $125,000 | $125,000 | $125,000 | $125,000 | $125,000 | $125,000 | $125,000 | $125,000 | $125,000 | $125,000 | $125,000 | $125,000 | $1,500,000 |
| | b. Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other (A) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3 | Less: Accumulated Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 125,000 | 250,000 | 375,000 | 500,000 | 625,000 | 750,000 | 875,000 | 1,000,000 | 1,125,000 | 1,250,000 | 1,375,000 | 1,500,000 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | | $0 | 125,000 | 250,000 | 375,000 | 500,000 | 625,000 | 750,000 | 875,000 | 1,000,000 | 1,125,000 | 1,250,000 | 1,375,000 | 1,500,000 | |
| 6 | Average Net Investment | | | 62,500 | 187,500 | 312,500 | 437,500 | 562,500 | 687,500 | 812,500 | 937,500 | 1,062,500 | 1,187,500 | 1,312,500 | 1,437,500 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) | 10.75% | | 560 | 1,680 | 2,799 | 3,919 | 5,039 | 6,159 | 7,279 | 8,398 | 9,518 | 10,638 | 11,758 | 12,878 | $80,625 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) | 2.57% | | 134 | 402 | 669 | 937 | 1,205 | 1,472 | 1,740 | 2,008 | 2,276 | 2,543 | 2,811 | 3,079 | 19,275 |
| 8 | Investment Expenses | | | | | | | | | | | | | | | |
| | a. Depreciation (E) | 3.70% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | d. Property Taxes (I) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other (F) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | | 694 | 2,081 | 3,469 | 4,856 | 6,244 | 7,631 | 9,019 | 10,406 | 11,794 | 13,181 | 14,569 | 15,956 | 99,901 |
| | a. Recoverable Costs Allocated to Energy | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | | 694 | 2,081 | 3,469 | 4,856 | 6,244 | 7,631 | 9,019 | 10,406 | 11,794 | 13,181 | 14,569 | 15,956 | 99,900 |
| 10 | Energy Jurisdictional Factor | | | 0.94678 | 0.94965 | 0.94437 | 0.94463 | 0.94488 | 0.95025 | 0.95308 | 0.95225 | 0.94974 | 0.94683 | 0.94053 | 0.94609 | |
| 11 | Demand Jurisdictional Factor - Production (Peaking) | | | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | 0.74562 | |
| 12 | Retail Energy-Related Recoverable Costs (G) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (H) | | | 517 | 1,552 | 2,587 | 3,621 | 4,656 | 5,690 | 6,725 | 7,759 | 8,794 | 9,828 | 10,863 | 11,897 | 74,487 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | | $ 517 | $ 1,552 | $ 2,587 | $ 3,621 | $ 4,656 | $ 5,690 | $ 6,725 | $ 7,759 | $ 8,794 | $ 9,828 | $ 10,863 | $ 11,897 | $ 74,487 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for Above Ground Tank Secondary Containment - Intercession City CTs project. None for this period.
(B) Applicable beginning of period and end of period depreciable base by Above Ground Tank Secondary Containment - Intercession City CTs.
(C) Adjustments to Reserve for Gross Salvage (none for this period) and Other Recoveries (none for this period) and Cost of Removal based on Depreciation Rate for Above Ground Tank Secondary Containment - Intercession City CTs.
(D) Line 6 x 10.7500% x 1/12. Based on ROE of 12.00%, weighted cost of equity component of capital structure of 6.61%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(E) Line 2 x 3.70% x 1/12. Depreciation rate based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI).
(F) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Intercession City CTs project. None for this period.
(G) Line 9a x Line 10 x 1.00000 line loss multiplier. None for this period.
(H) Line 9b x Line 11
(I) Lines 2 + 3 x .015989 x 1/12. Based on 2003 Actual Property Tax Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**JANUARY 2005 - DECEMBER 2005**

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances
**(in Dollars)**

| Line | Description | | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Working Capital Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 1581001 $SO_2$ Emission Allowance Inventory | | $3,569,255 | $3,192,172 | $2,840,486 | $4,694,385 | $6,251,428 | $7,367,636 | $8,093,026 | $8,319,287 | $8,101,005 | $7,616,909 | $6,802,389 | $5,545,400 | $2,134,110 | $2,134,110 |
| | b. 25401FL Auctioned $SO_2$ Allowance | | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) | (2,397,821) |
| 2 | Total Working Capital | | $ 1,171,434 | $794,352 | $442,666 | $2,296,565 | $3,853,606 | $4,969,815 | $5,695,205 | $5,921,467 | $5,703,185 | $5,221,089 | $4,404,569 | $3,147,579 | ($263,711) | $ (263,711) |
| 3 | Average Net Investment | | | 982,893 | 618,499 | 1,369,605 | 3,075,085 | 4,411,711 | 5,332,510 | 5,808,336 | 5,812,326 | 5,462,137 | 4,812,829 | 3,776,074 | 1,441,934 | |
| 4 | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (A) | 10.75% | | 6,805 | 5,541 | 12,269 | 27,548 | 39,522 | 47,770 | 52,033 | 52,069 | 48,932 | 43,115 | 33,827 | 12,917 | $384,348 |
| | b. Debt Component (Line 6 x 2.57% x 1/12) | 2.57% | | 2,105 | 1,325 | 2,933 | 6,586 | 9,448 | 11,420 | 12,440 | 12,448 | 11,698 | 10,307 | 6,087 | 3,088 | 91,886 |
| 5 | Total Return Component (D) | | | 10,910 | 6,865 | 15,203 | 34,133 | 48,970 | 59,191 | 64,473 | 64,517 | 60,630 | 53,422 | 41,914 | 16,005 | 476,234 |
| 6 | Expense Dr (Cr) | | | | | | | | | | | | | | | |
| | a. 5090001 $SO_2$ Allowance Expense | | | $377,083 | $351,706 | $368,303 | $665,181 | $1,106,012 | $1,496,833 | $1,995,961 | $2,440,504 | $2,704,316 | $3,038,742 | $3,479,211 | $3,411,290 | $21,435,145 |
| 7 | Net Expense (E) | | | 377,083 | 351,706 | 368,303 | 665,181 | 1,106,012 | 1,496,833 | 1,995,961 | 2,440,504 | 2,704,318 | 3,038,742 | 3,479,211 | 3,411,290 | 21,435,145 |
| 8 | Total System Recoverable Expenses (Lines 5 + 7) | | | 387,993 | 358,571 | 383,506 | 699,314 | 1,154,982 | 1,556,023 | 2,060,433 | 2,505,021 | 2,764,948 | 3,092,165 | 3,521,126 | 3,427,295 | |
| | a. Recoverable costs allocated to Energy | | | 387,993 | 358,571 | 383,506 | 699,314 | 1,154,982 | 1,556,023 | 2,060,433 | 2,505,021 | 2,764,948 | 3,092,165 | 3,521,126 | 3,427,295 | |
| | b. Recoverable costs allocated to Demand | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 9 | Energy Jurisdictional Factor | | | 0.94678 | 0.94965 | 0.94437 | 0.94463 | 0.94488 | 0.95025 | 0.95308 | 0.95225 | 0.94974 | 0.94683 | 0.94053 | 0.94609 | |
| 10 | Demand Jurisdictional Factor - n/a | | | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | |
| 11 | Retail Energy-Related Recoverable Costs (B) | | | 367,344 | 340,517 | 362,172 | 660,593 | 1,091,320 | 1,478,611 | 1,963,758 | 2,385,406 | 2,625,982 | 2,927,754 | 3,311,724 | 3,242,530 | 20,757,712 |
| 12 | Retail Demand-Related Recoverable Costs (C) | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Total Jurisdictional Recoverable Costs (Lines 11 + 12) | | | $ 367,344 | $ 340,517 | $ 362,172 | $ 660,593 | $ 1,091,320 | $ 1,478,611 | $ 1,963,758 | $ 2,385,406 | $ 2,625,982 | $ 2,927,754 | $ 3,311,724 | $ 3,242,530 | $ 20,757,712 |

Notes:
(A) Line 3 x 10.7500% x 1/12. Based on ROE of 12.00%, weighted cost of equity component of capital structure of 6.81%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI).
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
**JANUARY 2005 - DECEMBER 2005**
Description and Progress Report for
Environmental Compliance Activities and Projects

**Project Title:** Substation Environmental Investigation, Remediation, and Pollution Prevention
**Project No. 1**

**Project Description:**
Chapter 376, Florida Statutes, requires that any person discharging a prohibited pollutant shall undertake to contain, remove, and abate the discharge to the satisfaction of the Florida Department of Environmental Protection. Similarly, Chapter 403, Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For Progress Energy Florida to continue to comply with these statutes, it is conducting environmental investigation, remediation, and pollution prevention activities associated with its substation facilities to determine the existence of pollutant discharges, and if present, their removal and remediation. Activities also include development and implementation of best management and pollution prevention measures at these facilities.

**Project Accomplishments:**
Progress Energy Florida (PEF) has completed environmental investigations and necessary remediations at six substations in 2003. In addition, PEF began negotiating with the FDEP on the inspection, assessment and remediation procedures. These negotiations continued into 2004 and were completed in the 2nd quarter. The substation site inspections were completed subsequent to obtaining FDEP plan approval. PEF has produced a priority list of substation sites based on these inspections and agency assessment criteria. This list has been submitted to the FDEP for review and approval. This approval is necessary before site remediation activities can begin. PEF has also implemented the Best Management Practices which were required by the FDEP. The extended timeframe to complete the FDEP negotiations delayed the beginning of site remediation. The current schedule is to start site remediation sometime during the 4th quarter, 2004. This revised schedule resulted in a reduced scope of work orginally projected at 52 sites, down to the reprojected estimate of 9 sites by end of year 2004.

**Project Fiscal Expenditures:**
January 1, 2004 to December 31, 2004: Project expenditures are estimated to be $432,669 or 57% lower than originally projected. This variance resulted from a reduced scope of work associated with the remediation activities in Substations.

**Project Progress Summary:**
PEF is on schedule according to the approved Substation Inspection Plan and the Substation Assessment and Remedial Action Plan, and has already identified a total of 66 substation sites for 2005 requiring remediation.

**Project Projections:**
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $1,149,748 for remediation activity.

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
**JANUARY 2005 - DECEMBER 2005**
Description and Progress Report for
Environmental Compliance Activities and Projects

**Project Title:** Distribution System Environmental Investigation, Remediation, and Pollution Prevention
**Project No. 2**

**Project Description:**
Chapter 376, Florida Statutes, requires that any person discharging a prohibited pollutant shall undertake to contain, remove, and abate the discharge to the satisfaction of the Florida Department of Environmental Protection. Similarly, Chapter 403, Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For Progress Energy Florida to continue to comply with these statutes, it is conducting environmental investigation, remediation, and pollution prevention activities associated with its distribution system facilities to determine the existence of pollutant discharges, and if present, their removal and remediation. Activities also include development and implementation of best management and pollution prevention measures at these facilities.

**Project Accomplishments:**
Progress Energy completed remediation on 1,613 distribution padmount transformer sites in 2003. In 2004, PEF has targeted site remediation at a total of 709 distribution remediation sites consisting of 345 three-phase sites and 364 single-phase sites, of which a total of 244 sites have been completed.

**Project Fiscal Expenditures:**
January 1, 2004 to December 31, 2004: Project expenditures are estimated to be $2,930,034 or 57% higher than originally projected. This variance resulted from an increased cost estimate on three-phased sites based on actual costs experienced in 2004 and an increase of 364 single-phase sites targeted for the associated investigation and remediation activities.

**Project Progress Summary:**
This project is on schedule according to the approved DistributionSystem Investigation, Remediation and Pollution Prevention Program. PEF has identified a total of 784 distribution sites requiring remediation for 2005.

**Project Projections:**
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $7,354,748 for remediation activity.

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
**JANUARY 2005 - DECEMBER 2005**
Description and Progress Report for
Environmental Compliance Activities and Projects

**Project Title:** Pipeline Integrity Management, Review/Update Plan and Risk Assessments
**Project No. 3a**

**Project Description:**
The U.S. Department of Transportation ("USDOT") Regulation 49 CFR Part 195, as amended effective February 15, 2002 and the new regulation published at 67 Federal Register 2136 on January 16, 2002 requires PEF to implement a Pipeline Intergrity Management Program. Prior to the February 15, 2002 amendments, the USDOT's pipeline integrity management regulations applied only to operators with 500 miles or more of hazarddous liquid and carbon dioxide pipelines that could affect high consequence areas. The amendments which became effective on February 15, 2002 extended the requirments for implementing integrity management to operators to those who have less than 500 miles of regulated pipelines. As such, PEF must improve the integrity of pipeline systems in order to protect public safety and the environment, as well as complying with continual assessment and evaluation of pipeline systems integrity through inspection or testing, data integration and analysis and follow up remedial, preventative, and mitigative actions.

PEF owns one hazardous liquid pipeline that is subject to the new regulation and must comply with the new requirements for the Bartow/Anclote 14-inch hot oil pipeline which extends for 33.3 miles from the Company's Bartow Plant north of St. Petersburg in Pinellas County, to its Anclote Plant near Holiday in Pasco County.

**Project Accomplishments:**
During 2004, PEF continued work on the PIM program. This effort included performing the baseline integrity assessment, initiating the baseline assessment of the Bartow aboveground piping segment, and reviewing the results of the assessment. In recognition of the responsibility and increased workload associated with the PIM program, PEF created a new position solely devoted to oversight of the program. Based upon the results of the required risk assessments, PEF has also identified various remedial, preventative, and mitigative actions along the pipeline; these identified actions will be completed by the end of 2004.

**Project Fiscal Expenditures:**
January 1, 2004 to December 31, 2004: O&M project expenditures are estimated to be $745,000 or 304% higher than originally projected. This variance primarily resulted from more current estimates of the costs associated with required preventative measures, based on the results of pipeline inspections. Capital expenditures increased $211,060 for pipeline leak detection system plus $525,940 of expenses which were erroneously charged to non-recoverable O&M.

**Project Progress Summary:**
Review and updates to the integrity management plan and risk analyses continue on target. Compliance work will continue through the end of 2004, and will continue into the future.

**Project Projections:**
Estimated project O&M expenditures for the period January 2005 through December 2005 are expected to be $1,056,000.

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
**JANUARY 2005 - DECEMBER 2005**
Description and Progress Report for
Environmental Compliance Activities and Projects

**Project Title:** Above Ground Tank Secondary Containment
**Project No. 4**

**Project Description:**
Florida Department of Environmental Protection Rule 62-761.510(3) states that the Company is required to make improvements to many of its aboveground petroleum storage tanks in order to comply with those provisions. Subsection (d) of that rule requires all internally lined single bottom aboveground storage tanks to be upgraded with secondary containment, including secondary containment for piping in contact with the soil. Rule 62-761.500(1)(e) also requires that dike field area containment for pre-1998 tanks be upgraded, if needed, to comply with the requirement.

**Project Accomplishments:**
Activities during 2004 included upgrading of piping at the Bartow plant and installations of a secondary tank bottom at the Turner, Bartow, and Crystal River 1 & 2 plants.

**Project Fiscal Expenditures:**
January 1, 2004 to December 31, 2004: Project expenditures are basically flat when compared to the original projection.

**Project Progress Summary:**
PEF will continually evaluate its compliance program, including project prioritization, schedule, and technology applications.

**Project Projections:**
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $1,500,000.

Form 42-5P
Page 5 of 6

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
**JANUARY 2005 - DECEMBER 2005**
Description and Progress Report for
Environmental Compliance Activities and Projects

**Project Title:** $SO_2$ Emissions Allowances
**Project No. 5**

**Project Description:**
In accordance with the Clean Air Act Title IV Statute, Code of Federal Regulations Chapter 40, Part 73 and Florida State Regulation 62-214, PEF censors and operates activities associated with the $SO_2$ Emissions Allowance Inventory for the purpose of compliance of offsetting excess sulfur dioxide emissions as set forth by the Federal Acid Rain Program.

**Project Accomplishments:**
For purposes of compliance with an affected unit's sulfur dioxide Acid Rain emissions limitation requirements pursuant to Title IV of the Act, the environmental air quality compliance costs are administered by a designated and authorized account representative to evaluate the full range of resources in order to meet those rules governed by the Federal and State. Activities performed include purchases, auctions, and transfers in accordance to the EPA allowances and deemed in compliance with those requirements.

**Project Fiscal Expenditures:**
January 1, 2004 to December 31, 2004: Project expenditures are estimated to be $15,502,833 or 352% higher than originally projected. This variance was driven by both increases in projected tons of SO2 emmissions, and by higher market prices for allowances. The price variance is due in part to increased demand in the marketplace due to uncertainty associated with pending legislation on the Clean Air Interstate Ruling. The price of allowances increased from the previously projected average price of $160 per ton, to the current projected average price of $400 - $600 per ton. The increase in projected tons is driven by higher natureal gas prices which have resulted in more residual oil in the 2004 projected generation plan.

**Project Progress Summary:**
Effective with the 2004 Projection, PEF has transitioned this compliance regulation costs from the Fuel Adjustment Clause over to the ECRC Clause. Previously PEF did not have the ECRC Clause therefore, these costs were included with the Fuel Adjustment Clause.

**Project Projections:**
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $21,435,145.

**PROGRESS ENERGY FLORIDA**
Environmental Cost Recovery Clause (ECRC)
**JANUARY 2005 - DECEMBER 2005**
Description and Progress Report for
Environmental Compliance Activities and Projects

**Project Title:** Phase II Cooling Water Intake
**Project No. 6**

**Project Description:**
Section 316(b) of the Federal Clean Water Act, requires that "the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse envrionmental impact." 33 U.S.C. Section 1326. In the past, EPA and the state regulatory agency implemented Section 316(b) on a case-by-case basis. In the new Phase II rules, EPA has established "national performace standards" for determining compliance with Section 316(b) at certain existing electric generating facilities. See 40 CFR 125.94(b). The process of compliance involves planning and scheduling efforts, conducting certain biological studies, and evaluation of options for compliance. These compliance options involve engineering measures, opertional measures, restorative measures and/or cost assessment measures. See generally 40 CFR 125.94 and 125.95.

**Project Accomplishments:**
PEF facilities subject to EPA's new Phase II rules include Anclote, Bartow, Crystal River and Suwannee plants. Early in 2004 PEF competitivley bid environmental consultant support for the development of a Compliance Strategy and Implementation Plan (CSIP); that contract was secured and the CSIP is now complete. Work with the consultant has begun on the development of a Proposal for Information Collection.

**Project Fiscal Expenditures:**
PEF projected approximately $50,000 to $100,000 of O&M for activities necessary to develop the Compliance Strategy and Implementation Plan, and development of the Proposal for Information Collection during 2004.

**Project Progress Summary:**
Although environmental studies were conducted at Anclote, Bartow and Crystal River in the past, the results of the studies are not expected to sufficiently address the requirements of the new 316(b) Phase II rule, in particular those of the Comprehensive Demonstation Study (CDS). With the assistance of an environmental consultant, PEF has completed a Compliance Strategy and Implementation Plan (CSIP), and is now beginning work on development of the Proposal for Information Collection (PIC). The PIC will be submitted to the FDEP as the basis for discussions regarding field studies and data collection to occur in 2005. According to guidance recently issued by EPA, PEF may need to perform or initiate environmental studies at more than one site in 2005. PEF will actively work with FDEP / EPA to specify the required actions and associated schedules.

**Project Projections:**
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $600,632 for one site plus development of the Company's PIC.

**PROGRESS ENERGY FLORIDA** Form 42-6P

Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % by Rate Class
**JANUARY 2005 - DECEMBER 2005**

| Rate Class | (1) Average 12CP Load Factor at Meter (%) | (2) Sales at Meter (mWh) | (3) Avg 12 CP at Meter (MW) (2)/(8760hrsx(1)) | (4) NCP Class Max Load Factor | (5) Delivery Efficiency Factor | (6) Sales at Source (Generation) (mWh) (2)/(5) | (7) Avg 12 CP at Source (MW) (3)/(5) | 7(a) Sales at Source (Distrib Svc Only) (mWh) | (8) Class Max MW at Source Level (Distrib Svc) (7a)/(8760hrs/(4)) | (9) mWh Sales at Source Energy Allocator (%) | (10) 12CP Demand Transmission Allocator (%) | (11) 12CP & 1/13 AD Demand Allocator (%) | (12) NCP Distribution Allocator (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | | | | | | |
| **RS-1, RST-1, RSL-1, RSL-2, RSS-1** | | | | | | | | | | | | | |
| (Secondary) | 0.548 | 20,046,231 | 4,175.88 | 0.40979 | 0.9421658 | 21,276,755 | 4,432.21 | 21,276,755 | 5,927.0 | 49.929% | 56.915% | 56.377% | 58.011% |
| **General Service Non-Demand** | | | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | | | |
| Secondary | 0.609 | 1,333,086 | 249.88 | 0.43381 | 0.9421658 | 1,414,917 | 265.22 | 1,414,917 | 372.3 | 3.320% | 3.406% | 3.399% | 3.644% |
| Primary | 0.609 | 9,250 | 1.73 | 0.43381 | 0.9664000 | 9,572 | 1.79 | 9,572 | 2.5 | 0.022% | 0.023% | 0.023% | 0.025% |
| Transmission | 0.609 | 2,205 | 0.41 | 0.43381 | 0.9764000 | 2,258 | 0.42 | 0 | 0.0 | 0.005% | 0.005% | 0.005% | 0.000% |
| **General Service** | | | | | | | | | | | | | |
| **GS-2** (Secondary) | 1.000 | 85,275 | 9.73 | 1.00000 | 0.9421658 | 90,510 | 10.33 | 90,510 | 10.3 | 0.212% | 0.133% | 0.139% | 0.101% |
| **General Service Demand** | | | | | | | | | | | | | |
| **GSD-1** Transmission | 0.698 | 156 | 0.03 | 0.56422 | 0.9764000 | 160 | 0.03 | 0 | 0.0 | 0.000% | 0.000% | 0.000% | 0.000% |
| **SS-1** Primary | 3.733 | 9,174 | 0.28 | 0.18621 | 0.9664000 | 9,493 | 0.29 | 9,493 | 5.8 | 0.022% | 0.004% | 0.005% | 0.057% |
| Transmission | 3.733 | 6,332 | 0.25 | 0.18621 | 0.9764000 | 8,533 | 0.26 | 0 | 0.0 | 0.020% | 0.003% | 0.005% | 0.000% |
| **GSD-1** Secondary | 0.698 | 12,851,526 | 2,101.82 | 0.56422 | 0.9421658 | 13,640,408 | 2,230.64 | 13,640,408 | 2,759.8 | 32.009% | 28.646% | 28.905% | 27.012% |
| Primary | 0.698 | 2,762,073 | 451.73 | 0.56422 | 0.9664000 | 2,858,105 | 467.43 | 2,858,105 | 578.3 | 6.707% | 6.002% | 6.057% | 5.660% |
| **Curtailable** | | | | | | | | | | | | | |
| **CS-1, CST-1, CS-2, CST-2, SS-3** | | | | | | | | | | | | | |
| Secondary | 0.779 | 375 | 0.05 | 0.56424 | 0.9421658 | 398 | 0.06 | 398 | 0.1 | 0.001% | 0.001% | 0.001% | 0.001% |
| Primary | 0.779 | 202,249 | 29.64 | 0.56424 | 0.9664000 | 209,281 | 30.67 | 209,281 | 42.3 | 0.491% | 0.394% | 0.401% | 0.414% |
| **SS-3** (Primary) | 0.480 | 4,310 | 1.03 | 0.02458 | 0.9664000 | 4,460 | 1.06 | 4,460 | 20.7 | 0.010% | 0.014% | 0.013% | 0.203% |
| **Interruptible** | | | | | | | | | | | | | |
| **IS-1, IST-1, IS-2, IST-2** | | | | | | | | | | | | | |
| Secondary | 0.940 | 147,996 | 17.97 | 0.67161 | 0.9421658 | 157,081 | 19.08 | 157,081 | 26.7 | 0.369% | 0.245% | 0.254% | 0.261% |
| Primary | 0.940 | 1,899,679 | 230.72 | 0.67161 | 0.9664000 | 1,965,934 | 238.75 | 1,965,934 | 334.2 | 4.613% | 3.066% | 3.185% | 3.271% |
| Transmission | 0.940 | 451,210 | 54.80 | 0.67161 | 0.9764000 | 462,116 | 56.12 | 0 | 0.0 | 1.084% | 0.721% | 0.749% | 0.000% |
| **SS-2** Primary | 0.748 | 80,926 | 12.35 | 0.17340 | 0.9664000 | 83,740 | 12.78 | 83,740 | 55.1 | 0.197% | 0.164% | 0.167% | 0.540% |
| Transmission | 0.748 | 74,811 | 11.42 | 0.17340 | 0.9764000 | 76,619 | 11.69 | 0 | 0.0 | 0.180% | 0.150% | 0.152% | 0.000% |
| **Lighting** | | | | | | | | | | | | | |
| **LS-1** (Secondary) | 4.650 | 323,633 | 7.95 | 0.47900 | 0.9421658 | 343,499 | 8.43 | 343,499 | 81.9 | 0.806% | 0.108% | 0.162% | 0.801% |
| | | 40,292,697 | 7,357.67 | | | 42,813,838 | 7,787.47 | 42,064,152 | 10,217.1 | 100.000% | 100.000% | 100.000% | 100.000% |

Notes:
(1) Average 12CP load factor based on load research study filed July 31, 2003
(2) Projected kWh sales for the period January 2005 to December 2005
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2003
(5) Based on system average line loss analysis for 2003
(6) Column 2 / Column 5
(7) Column 3 / Column 5
(7a) Column 6 excluding transmission service
(8) Calculated: Column 7a / (8,760 hours/ Column 4)
(9) Column 6/ Total Column 6
(10) Column 7/ Total Column 7
(11) Column 9 x 1/13 + Column 10 x 12/13
(12) Column 8/ Total Column 8

**PROGRESS ENERGY FLORIDA**

Form 42-7P

Environmental Cost Recovery Clause (ECRC)

Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class

**JANUARY 2005 - DECEMBER 2005**

| Rate Class | (1) mWh Sales at Source Energy Allocator (%) | (2) 12CP Demand Transmission Allocator (%) | (3) 12CP & 1/13 AD Demand Allocator (%) | (4) NCP Distribution Allocator (%) | (5) Energy-Related Costs ($) | (6) Transmission Demand Costs ($) | (7) Distribution Demand Costs ($) | (8) Production Demand Costs ($) | (9) Total Environmental Costs ($) | (10) Projected Effective Sales at Meter Level (mWh) | (11) Environmental Cost Recovery Factors (cents/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | | | | |
| **RS-1, RST-1, RSL-1, RSL-2, RSS-1** | | | | | | | | | | | |
| (Secondary) | 49.929% | 56.915% | 56.377% | 58.011% | $16,777,745 | $529,696 | $6,892,809 | $1,240,067 | $25,440,336 | 20,046,231 | 0.127 |
| **General Service Non-Demand** | | | | | | | | | | | |
| **GS-1, GST-1** | | | | | | | | | | | |
| Secondary | 3.320% | 3.406% | 3.399% | 3.644% | $1,115,730 | $31,697 | $432,997 | $74,769 | $1,655,193 | 1,333,066 | 0.124 |
| Primary | 0.022% | 0.023% | 0.023% | 0.025% | $7,548 | $214 | $2,929 | $506 | $11,197 | 9,156 | 0.123 |
| Transmission | 0.005% | 0.005% | 0.005% | 0.000% | $1,781 | $51 | $0 | $119 | $1,951 | 2,161 | 0.122 |
| **TOTAL GS** | | | | | **$1,125,058** | **$31,962** | **$435,926** | **$75,394** | **$1,668,340** | **1,344,405** | |
| **General Service** | | | | | | | | | | | |
| **GS-2** (Secondary) | 0.212% | 0.133% | 0.139% | 0.101% | $71,371 | $1,235 | $12,016 | $3,053 | $87,675 | 85,275 | 0.103 |
| **General Service Demand** | | | | | | | | | | | |
| **GSD-1** Transmission | 0.000% | 0.000% | 0.000% | 0.000% | $126 | $3 | $0 | $7 | $137 | 153 | 0.113 |
| **SS-1** Primary | 0.022% | 0.004% | 0.005% | 0.057% | $7,486 | $35 | $6,768 | $113 | $14,402 | 9,082 | 0.114 |
| Transmission | 0.020% | 0.003% | 0.005% | 0.000% | $6,729 | $31 | $0 | $102 | $6,862 | 8,165 | 0.113 |
| **GSD-1** Secondary | 32.009% | 28.646% | 28.905% | 27.012% | $10,756,118 | $266,608 | $3,209,490 | $635,804 | $14,868,019 | 12,851,526 | 0.115 |
| Primary | 6.707% | 6.002% | 6.057% | 5.660% | $2,253,754 | $55,863 | $672,492 | $133,221 | $3,115,329 | 2,734,452 | 0.114 |
| **TOTAL GSD** | | | | | **$13,024,212** | **$322,540** | **$3,888,749** | **$769,248** | **$18,004,749** | **15,603,379** | |
| **Curtailable** | | | | | | | | | | | |
| **CS-1, CST-1, CS-2, CST-2, SS-3** | | | | | | | | | | | |
| Secondary | 0.001% | 0.001% | 0.001% | 0.001% | $314 | $7 | $94 | $17 | $431 | 375 | 0.125 |
| Primary | 0.491% | 0.394% | 0.401% | 0.414% | $165,028 | $3,665 | $49,240 | $8,827 | $226,761 | 200,227 | 0.124 |
| **SS-3** (Primary) | 0.010% | 0.014% | 0.013% | 0.203% | $3,517 | $127 | $24,088 | $294 | $28,025 | 4,267 | 0.124 |
| **TOTAL CS** | | | | | **$168,859** | **$3,799** | **$73,422** | **$9,138** | **$255,217** | **204,868** | |
| **Interruptible** | | | | | | | | | | | |
| **IS-1, IST-1, IS-2, IST-2** | | | | | | | | | | | |
| Secondary | 0.369% | 0.245% | 0.254% | 0.261% | $123,866 | $2,280 | $31,050 | $5,597 | $162,793 | 147,996 | 0.106 |
| Primary | 4.613% | 3.066% | 3.185% | 3.271% | $1,550,234 | $28,533 | $388,607 | $70,054 | $2,037,428 | 1,880,880 | 0.105 |
| Transmission | 1.084% | 0.721% | 0.749% | 0.000% | $364,401 | $6,707 | $0 | $16,467 | $387,575 | 442,186 | 0.104 |
| **SS-2** Primary | 0.197% | 0.164% | 0.167% | 0.540% | $66,033 | $1,527 | $64,112 | $3,665 | $135,337 | 80,117 | 0.105 |
| Transmission | 0.180% | 0.150% | 0.152% | 0.000% | $60,418 | $1,397 | $0 | $3,353 | $65,168 | 73,315 | 0.104 |
| **TOTAL IS** | | | | | **$2,164,951** | **$40,444** | **$483,769** | **$99,136** | **$2,788,300** | **2,624,494** | |
| **Lighting** | | | | | | | | | | | |
| **LS-1** (Secondary) | 0.806% | 0.108% | 0.162% | 0.801% | $270,865 | $1,008 | $95,202 | $3,563 | $370,638 | 323,633 | 0.115 |
| | 100.000% | 100.000% | 100.000% | 100.000% | $33,603,061 | $930,683 | $11,881,893 | $2,199,619 | $48,615,256 | 40,232,285 | 0.121 |

Notes:

(1) From Form 42-6P, Column 9

(2) From Form 42-6P, Column 10

(3) From Form 42-6P, Column 11

(4) From Form 42-6P, Column 12

(5) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5

(6) Column 2 x Total Transmission Demand Jurisdictional Dollars from Form 42-1P, line 5

(7) Column 4 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5

(8) Column 3 x Total Production Demand Jurisdictional Dollars from Form 42-1P, line 5

(9) Column 5 + Column 6 + Column 7 + Column 8

(10) Projected kWh sales at effective voltage level for the period January 2005 to December 2005

(11) Column 7/ Column 8 x 100

EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)

TAMPA ELECTRIC COMPANY

EXHIBIT TO THE TESTIMONY OF

HOWARD T. BRYANT

ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

42-1A THROUGH 42-8A

JANUARY 2003 - DECEMBER 2003

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040007-EI EXHIBIT NO. 11
COMPANY/ TECO
WITNESS: Howard T. Bryant (HTB-1)
DATE: 11-08-04

EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)

# INDEX

## ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

## JANUARY 2003 THROUGH DECEMBER 2003

## 42-1A THROUGH 42-8A


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**Tampa Electric Company** Form 42 - 1A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
**January 2003 to December 2003**
(in Dollars)

| Line | | Period Amount |
|---|---|---|
| 1 | End of Period Actual True-Up for the Period January 2003 to December 2003 (Form 42-2A, Lines 5 + 6 +10) | ($424,154) |
| 2 | Estimated/Actual True-Up Amount Approved for the Period January 2003 to December 2003 (Order No. PSC-03-1348-FOF-EI) | (163,803) |
| 3 | Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2005 to December 2005 (Line 1 - 2) | ($260,351) |



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
DOCUMENT NO. 1
PAGE 1 OF 1
FORM 42-1A
FILED: APRIL 1, 2004

Form 42 - 2A

**Tampa Electric Company**
**Environmental Cost Recovery Clause (ECRC)**
Calculation of the Final True-Up Amount for the Period
**January 2003 to December 2003**

**Current Period True-Up Amount**
**(in Dollars)**

| Line | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. ECRC Revenues (net of Revenue Taxes) | $2,111,452 | $1,955,605 | $1,786,339 | $1,913,053 | $2,245,103 | $2,377,138 | $2,423,943 | $2,460,555 | $2,413,393 | $2,250,287 | $2,040,360 | $1,997,390 | $25,974,618 |
| 2. True-Up Provision | 204,677 | 204,677 | 204,677 | 204,677 | 204,677 | 204,677 | 204,677 | 204,677 | 204,677 | 204,677 | 204,677 | 204,678 | 2,456,125 |
| 3. ECRC Revenues Applicable to Period (Lines 1 + 2) | 2,316,129 | 2,160,282 | 1,991,016 | 2,117,730 | 2,449,780 | 2,581,815 | 2,628,620 | 2,665,232 | 2,618,070 | 2,454,964 | 2,245,037 | 2,202,068 | 28,430,743 |
| 4. Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| a. O & M Activities (Form 42-5A, Line 9) | 420,847 | 388,081 | 481,446 | 431,221 | 950,385 | 640,375 | 630,963 | 796,936 | 542,989 | 597,247 | 747,614 | 1,025,164 | 7,653,268 |
| b. Capital Investment Projects (Form 42-7A, Line 9) | 1,781,135 | 1,784,311 | 1,753,835 | 1,768,058 | 1,765,907 | 1,769,537 | 1,767,339 | 1,765,651 | 1,760,839 | 1,761,696 | 1,760,257 | 1,760,561 | 21,199,126 |
| c. Total Jurisdictional ECRC Costs | 2,201,982 | 2,172,392 | 2,235,281 | 2,199,279 | 2,716,292 | 2,409,912 | 2,398,302 | 2,562,587 | 2,303,828 | 2,358,943 | 2,507,871 | 2,785,725 | 28,852,394 |
| 5. Over/Under Recovery (Line 3 - Line 4c) | 114,147 | (12,110) | (244,265) | (81,549) | (266,512) | 171,903 | 230,318 | 102,645 | 314,242 | 96,021 | (262,834) | (583,657) | (421,651) |
| 6. Interest Provision (Form 42-3A, Line 10) | 2,079 | 1,881 | 1,475 | 1,083 | 717 | 428 | 393 | 373 | 377 | 378 | 120 | (418) | 8,886 |
| 7. Beginning Balance True-Up & Interest Provision | 2,456,125 | 2,356,285 | 2,141,379 | 1,693,912 | 1,408,769 | 938,297 | 905,951 | 931,985 | 830,326 | 940,268 | 831,990 | 364,599 | 2,456,125 |
| a. Deferred True-Up from January to December 2002 (Order No. PSC-03-1348-FOF-EI) | (456,568) | (456,568) | (456,568) | (456,568) | (456,568) | (456,568) | (456,568) | (456,568) | (456,568) | (456,568) | (456,568) | (456,568) | (456,568) |
| 8. True-Up Collected/(Refunded) (see Line 2) | (204,677) | (204,677) | (204,677) | (204,677) | (204,677) | (204,677) | (204,677) | (204,677) | (204,677) | (204,677) | (204,677) | (204,678) | (2,456,125) |
| 9. End of Period Total True-Up (Lines 5 + 6 + 7 +7a + 8) | 1,911,106 | 1,684,811 | 1,237,344 | 952,201 | 481,729 | 449,383 | 475,417 | 373,758 | 483,700 | 375,422 | (91,969) | (880,722) | (869,333) |
| 10. Adjustment to Period True-Up Including Interest | (11,389) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (11,389) |
| 11. End of Period Total Net True-Up (Lines 9 + 10) | $1,899,717 | $1,684,811 | $1,237,344 | $952,201 | $481,729 | $449,383 | $475,417 | $373,758 | $483,700 | $375,422 | ($91,969) | ($880,722) | ($880,722) |

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EXHIBIT NO.
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
DOCUMENT NO. 2
PAGE 1 OF 1
FORM 42-2A
FILED: APRIL 1, 2004

Form 42 - 3A

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual True-Up Amount for the Period
**January 2003 to December 2003**

**Interest Provision**
(in Dollars)

| Line | | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Beginning Balance True-Up Amount (Form 42-2A, Line 7 +7a + 10) | $1,988,168 | $1,899,717 | $1,684,811 | $1,237,344 | $952,201 | $481,729 | $449,383 | $475,417 | $373,758 | $483,700 | $375,422 | ($91,969) | |
| 2. | Ending True-Up Amount Before Interest | 1,897,638 | 1,682,930 | 1,235,869 | 951,118 | 481,012 | 448,955 | 475,024 | 373,385 | 483,323 | 375,044 | (92,089) | (880,304) | |
| 3. | Total of Beginning & Ending True-Up (Lines 1 & 2) | 3,885,806 | 3,582,647 | 2,920,680 | 2,188,462 | 1,433,213 | 930,684 | 924,407 | 848,802 | 857,081 | 858,744 | 283,333 | (972,273) | |
| 4. | Average True-Up Amount (Line 3 x 1/2) | 1,942,903 | 1,791,324 | 1,460,340 | 1,094,231 | 716,607 | 465,342 | 462,204 | 424,401 | 428,541 | 429,372 | 141,667 | (486,137) | |
| 5. | Interest Rate (First Day of Reporting Business Month) | 1.29% | 1.27% | 1.25% | 1.18% | 1.19% | 1.21% | 1.00% | 1.05% | 1.06% | 1.06% | 1.05% | 1.00% | |
| 6. | Interest Rate (First Day of Subsequent Business Month) | 1.27% | 1.25% | 1.18% | 1.19% | 1.21% | 1.00% | 1.05% | 1.06% | 1.06% | 1.05% | 1.00% | 1.06% | |
| 7. | Total of Beginning & Ending Interest Rates (Lines 5 & 6) | 2.56% | 2.52% | 2.43% | 2.37% | 2.40% | 2.21% | 2.05% | 2.11% | 2.12% | 2.11% | 2.05% | 2.06% | |
| 8. | Average Interest Rate (Line 7 x 1/2) | 1.280% | 1.260% | 1.215% | 1.185% | 1.200% | 1.105% | 1.025% | 1.055% | 1.060% | 1.055% | 1.025% | 1.030% | |
| 9. | Monthly Average Interest Rate (Line 8 x 1/12) | 0.107% | 0.105% | 0.101% | 0.099% | 0.100% | 0.092% | 0.085% | 0.088% | 0.088% | 0.088% | 0.085% | 0.086% | |
| 10. | Interest Provision for the Month (Line 4 x Line 9) | $2,079 | $1,881 | $1,475 | $1,083 | $717 | $428 | $393 | $373 | $377 | $378 | $120 | ($418) | $8,886 |



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
DOCUMENT NO. 3
PAGE 1 OF 1
FORM 42-3A
FILED: APRIL 1, 2004

**Tampa Electric Company** Form 42 - 4A

Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

**Variance Report of O & M Activities**
(In Dollars)

| Line No. | | (1) Actual | (2) Actual/Estimated Projection | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1. | Description of O&M Activities | | | | |
| | 1a Big Bend Unit 3 Flue Gas Desulfurization Integration | $2,183,495 | $2,123,461 | $60,034 | 2.8% |
| | 1b Big Bend Units 1 & 2 Flue Gas Conditioning | 0 | 0 | 0 | 0.0% |
| | 1c $SO_2$ Emissions Allowances | (214,949) | (389,498) | 174,549 | 44.8% |
| | 1d Big Bend Units 1 & 2 FGD | 4,790,354 | 4,844,601 | (54,247) | -1.1% |
| | 1e Big Bend FGD Optimization and Utilization | (884) | (884) | 0 | 0.0% |
| | 1f Big Bend PM Minimization and Monitoring | 838,759 | 850,167 | (11,408) | -1.3% |
| | 1g Big Bend $NO_x$ Emissions Reduction | 201,990 | 250,000 | (48,010) | -19.2% |
| | 1h NPDES Annual Surveillance Fees | 43,700 | 43,700 | 0 | 0.0% |
| | 1i Gannon Thermal Discharge Study | 24,030 | 20,422 | 3,608 | 17.7% |
| | 1j Polk $NO_x$ Emissions Reduction | 8,935 | 16,400 | (7,465) | -45.5% |
| | 1k Bayside SCR Consumables | 19,588 | 66,246 | (46,658) | -70.4% |
| 2. | Total Investment Projects - Recoverable Costs | $7,895,018 | $7,824,615 | $70,403 | 0.9% |
| 3. | Recoverable Costs Allocated to Energy | $7,827,288 | $7,760,493 | $66,795 | 0.9% |
| 4. | Recoverable Costs Allocated to Demand | $67,730 | $64,122 | $3,608 | 5.6% |

Notes:
Column (1) is the End of Period Totals on Form 42-5A.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
DOCUMENT NO. 4
PAGE 1 OF 1
FORM 42-4A
FILED: APRIL 1, 2004

Form 42 - 5A

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calcualtion of the Actual Period Amount
**January 2003 to December 2003**

**O&M Activities**
(in Dollars)

| Line | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. Description of O&M Activities | | | | | | | | | | | | | | | |
| 1a Big Bend Unit 3 Flue Gas Desulfurization Integration | $143,286 | $102,287 | $168,738 | $176,913 | $134,502 | $192,349 | $168,846 | $232,575 | $173,810 | $185,423 | $256,065 | $248,701 | $2,183,495 | | $2,183,495 |
| 1b Big Bend Units 1 & 2 Flue Gas Conditioning | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| 1c $SO_2$ Emissions Allowances | (159,799) | (22,333) | (141,032) | (83,796) | 288,456 | (30,008) | (15,714) | (6,410) | (52,802) | (14,501) | (1,510) | 24,500 | (214,949) | | (214,949) |
| 1d Big Bend Units 1 & 2 FGD | 405,984 | 236,693 | 464,857 | 339,769 | 453,475 | 382,012 | 390,320 | 375,930 | 345,573 | 376,390 | 342,631 | 676,720 | 4,790,354 | | 4,790,354 |
| 1e Big Bend FGD Optimization and Utilization | (884) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (884) | | (884) |
| 1f Big Bend PM Minimization and Monitoring | 1,008 | 82,277 | 594 | 8,585 | 77,225 | 81,775 | 78,205 | 198,100 | 48,645 | 15,829 | 160,735 | 85,781 | 838,759 | | 838,759 |
| 1g Big Bend $NO_x$ Emissions Reduction | 0 | 0 | 23 | 223 | 29,396 | 28,061 | 25,000 | 19,316 | 29,658 | 51,706 | 3,407 | 15,200 | 201,990 | | 201,990 |
| 1h NPDES Annual Surveillance Fees | 43,700 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 43,700 | $43,700 | |
| 1i Gannon Thermal Discharge Study | 1,416 | 0 | 9,123 | 3,883 | 0 | 0 | 2,424 | 0 | 7,082 | (1,479) | 0 | 1,581 | 24,030 | 24,030 | |
| 1j Polk $NO_x$ Reduction | 0 | 0 | 0 | 0 | 0 | 0 | 1,556 | 1,564 | 1,396 | 1,396 | 1,578 | 1,445 | 8,935 | | 8,935 |
| 1k Bayside SCR and Ammonia | 0 | 0 | 0 | 0 | 0 | 6,246 | 0 | 0 | 6,671 | 0 | 6,671 | 0 | 19,588 | | 19,588 |
| 2 Total of O&M Activities | 434,711 | 398,924 | 502,303 | 445,577 | 983,054 | 660,435 | 650,637 | 821,075 | 560,033 | 614,764 | 769,577 | 1,053,928 | 7,895,018 | $67,730 | $7,827,288 |
| 3. Recoverable Costs Allocated to Energy | 389,595 | 398,924 | 493,180 | 441,694 | 983,054 | 660,435 | 648,213 | 821,075 | 552,951 | 616,243 | 769,577 | 1,052,347 | 7,827,288 | | |
| 4. Recoverable Costs Allocated to Demand | 45,116 | 0 | 9,123 | 3,883 | 0 | 0 | 2,424 | 0 | 7,082 | (1,479) | 0 | 1,581 | 67,730 | | |
| 5. Retail Energy Jurisdictional Factor | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | | | |
| 6. Retail Demand Jurisdictional Factor | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | | | |
| 7. Jurisdictional Energy Recoverable Costs (A) | 377,790 | 388,081 | 472,739 | 427,515 | 950,385 | 640,375 | 628,650 | 796,936 | 536,230 | 598,659 | 747,614 | 1,023,655 | 7,588,629 | | |
| 8. Jurisdictional Demand Recoverable Costs (B) | 43,057 | 0 | 8,707 | 3,706 | 0 | 0 | 2,313 | 0 | 6,759 | (1,412) | 0 | 1,509 | 64,639 | | |
| 9. Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $420,847 | $388,081 | $481,446 | $431,221 | $950,385 | $640,375 | $630,963 | $796,936 | $542,989 | $597,247 | $747,614 | $1,025,164 | $7,653,268 | | |

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
DOCUMENT NO. 5
PAGE 1 OF 1
FORM 42-5A
FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

**Variance Report of Capital Investment Projects - Recoverable Costs**
(In Dollars)

| Line No. | | (1) Actual | (2) Actual/Estimated Projection | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1. | Description of Investment Projects | | | | |
| 1a | Big Bend Unit 3 Flue Gas Desulfurization Integration | $976,427 | $976,427 | $0 | 0.0% |
| 1b | Big Bend Units 1 & 2 Flue Gas Conditioning | 603,129 | 603,129 | 0 | 0.0% |
| 1c | Big Bend Unit 4 Continuous Emissions Monitors | 100,608 | 100,608 | 0 | 0.0% |
| 1d | Gannon Ignition Oil Tank | 217,898 | 217,898 | 0 | 0.0% |
| 1e | Big Bend Fuel Oil Tank #1 Upgrade | 64,133 | 64,133 | 0 | 0.0% |
| 1f | Big Bend Fuel Oil Tank #2 Upgrade | 105,465 | 105,465 | 0 | 0.0% |
| 1g | Phillips Upgrade Tank #1 for FDEP | 7,604 | 7,604 | 0 | 0.0% |
| 1h | Phillips Upgrade Tank #4 for FDEP | 11,965 | 11,965 | 0 | 0.0% |
| 1i | Gannon Unit 5 Classifier Replacement | 527,728 | 527,728 | 0 | 0.0% |
| 1j | Gannon Unit 6 Classifier Replacement | 590,375 | 590,375 | 0 | 0.0% |
| 1k | Big Bend Unit 1 Classifier Replacement | 181,194 | 181,194 | 0 | 0.0% |
| 1l | Big Bend Unit 2 Classifier Replacement | 132,558 | 132,558 | 0 | 0.0% |
| 1m | Gannon Coal Crusher ($NO_x$ Control) | 2,168,390 | 2,168,390 | 0 | 0.0% |
| 1n | Big Bend Units 1 & 2 FGD | 11,678,268 | 11,678,268 | 0 | 0.0% |
| 1o | Big Bend Section 114 Mercury Testing Platform | 15,895 | 15,895 | 0 | 0.0% |
| 1p | Big Bend FGD Optimization and Utilization | 3,034,501 | 2,981,723 | 52,778 | 1.8% |
| 1q | Big Bend PM Minimization and Monitoring | 736,936 | 736,944 | (8) | 0.0% |
| 1r | Big Bend $NO_x$ Emissions Reduction | 528,059 | 521,571 | 6,488 | 1.2% |
| 1s | Polk $NO_x$ Emissions Reduction | 136,723 | 141,280 | (4,557) | -3.2% |
| 1t | Big Bend Unit 4 SOFA | 59,832 | 85,129 | (25,297) | -29.7% |
| 2. | Total Investment Projects - Recoverable Costs | $21,877,688 | $21,848,284 | $29,404 | 0.1% |
| 3. | Recoverable Costs Allocated to Energy | $21,470,623 | $21,441,219 | $29,404 | 0.1% |
| 4. | Recoverable Costs Allocated to Demand | $407,065 | $407,065 | $0 | 0.0% |

Notes:
Column (1) is the End of Period Totals on Form 42-7A.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
DOCUMENT NO. 6
PAGE 1 OF 1
FORM 42-6A
FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calcualtion of the Actual Period Amount
**January 2003 to December 2003**

Form 42 - 7A

**Capital Investment Projects-Recoverable Costs**
(in Dollars)

| Line | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. Description of Investment Projects (A) | | | | | | | | | | | | | | | |
| 1a Big Bend Unit 3 Flue Gas Desulfurization Integratic | $82,395 | $82,209 | $82,021 | $81,835 | $81,649 | $81,462 | $81,276 | $81,090 | $80,902 | $80,716 | $80,529 | $80,343 | $976,427 | | $976,427 |
| 1b Big Bend Units 1 & 2 Flue Gas Conditioning | 51,132 | 50,974 | 50,816 | 50,657 | 50,499 | 50,340 | 50,182 | 50,023 | 49,864 | 49,706 | 49,547 | 49,389 | 603,129 | | 603,129 |
| 1c Big Bend Unit 4 Continuous Emissions Monitors | 8,488 | 8,469 | 8,451 | 8,431 | 8,412 | 8,394 | 8,374 | 8,356 | 8,337 | 8,317 | 8,299 | 8,280 | 100,608 | | 100,608 |
| 1d Gannon Ignition Oil Tank | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,159 | 18,159 | 217,898 | $217,898 | |
| 1e Big Bend Fuel Oil Tank #1 Upgrade | 5,405 | 5,393 | 5,382 | 5,372 | 5,361 | 5,349 | 5,339 | 5,328 | 5,318 | 5,306 | 5,295 | 5,285 | 64,133 | 64,133 | |
| 1f Big Bend Fuel Oil Tank #2 Upgrade | 8,887 | 8,869 | 8,851 | 8,833 | 8,815 | 8,798 | 8,780 | 8,762 | 8,744 | 8,727 | 8,708 | 8,691 | 105,465 | 105,465 | |
| 1g Phillips Upgrade Tank #1 for FDEP | 643 | 642 | 640 | 638 | 636 | 635 | 632 | 631 | 630 | 627 | 626 | 624 | 7,604 | 7,604 | |
| 1h Phillips Upgrade Tank #4 for FDEP | 1,012 | 1,009 | 1,007 | 1,004 | 1,001 | 999 | 996 | 993 | 991 | 987 | 984 | 982 | 11,965 | 11,965 | |
| 1i Gannon Unit 5 Classifier Replacement | 46,195 | 45,792 | 45,389 | 44,985 | 44,582 | 44,179 | 43,776 | 43,372 | 42,970 | 42,566 | 42,162 | 41,760 | 527,728 | | 527,728 |
| 1j Gannon Unit 6 Classifier Replacement | 51,677 | 51,227 | 50,776 | 50,325 | 49,873 | 49,422 | 48,971 | 48,520 | 48,069 | 47,618 | 47,167 | 46,730 | 590,375 | | 590,375 |
| 1k Big Bend Unit 1 Classifier Replacement | 15,334 | 15,292 | 15,248 | 15,206 | 15,164 | 15,120 | 15,078 | 15,036 | 14,993 | 14,950 | 14,908 | 14,865 | 181,194 | | 181,194 |
| 1l Big Bend Unit 2 Classifier Replacement | 11,213 | 11,183 | 11,153 | 11,122 | 11,092 | 11,062 | 11,031 | 11,001 | 10,971 | 10,940 | 10,910 | 10,880 | 132,558 | | 132,558 |
| 1m Gannon Coal Crusher ($NO_x$ Control) | 189,813 | 188,155 | 186,498 | 184,842 | 183,185 | 181,527 | 179,871 | 178,214 | 176,557 | 174,900 | 173,243 | 171,585 | 2,168,390 | | 2,168,390 |
| 1n Big Bend Units 1 & 2 FGD | 988,716 | 985,894 | 983,070 | 980,247 | 977,423 | 974,601 | 971,778 | 968,954 | 966,131 | 963,308 | 960,485 | 957,661 | 11,678,268 | | 11,678,268 |
| 1o Big Bend Section 114 Mercury Testing Platform | 1,338 | 1,335 | 1,332 | 1,331 | 1,328 | 1,326 | 1,323 | 1,322 | 1,319 | 1,316 | 1,314 | 1,311 | 15,895 | | 15,895 |
| 1p Big Bend FGD Optimization and Utilization | 255,581 | 255,089 | 254,597 | 254,104 | 253,613 | 253,121 | 252,629 | 252,137 | 251,646 | 251,154 | 250,661 | 250,169 | 3,034,501 | | 3,034,501 |
| 1q Big Bend PM Minimization and Monitoring | 60,269 | 61,381 | 59,569 | 58,251 | 60,053 | 61,711 | 62,931 | 63,174 | 62,584 | 61,882 | 62,252 | 62,879 | 736,936 | | 736,936 |
| 1r Big Bend $NO_x$ Emissions Reduction | 38,565 | 40,313 | 41,081 | 41,757 | 42,848 | 43,644 | 44,114 | 45,068 | 46,463 | 47,766 | 48,619 | 47,821 | 528,059 | | 528,059 |
| 1s Polk $NO_x$ Emissions Reduction | 2,510 | 3,428 | 5,780 | 9,834 | 12,820 | 13,702 | 14,224 | 14,586 | 14,786 | 14,962 | 15,034 | 15,057 | 136,723 | | 136,723 |
| 1t Big Bend Unit 4 SOFA | 0 | 0 | 0 | 243 | 532 | 1,953 | 3,414 | 4,974 | 6,849 | 10,132 | 13,662 | 18,073 | 59,832 | | 59,832 |
| 2. Total Investment Projects - Recoverable Costs | 1,837,331 | 1,834,812 | 1,829,819 | 1,827,175 | 1,827,044 | 1,825,503 | 1,822,877 | 1,819,699 | 1,816,282 | 1,814,038 | 1,812,564 | 1,810,544 | 21,877,688 | $407,065 | $21,470,623 |
| 3. Recoverable Costs Allocated to Energy | 1,803,226 | 1,800,741 | 1,795,781 | 1,793,170 | 1,793,073 | 1,791,564 | 1,788,972 | 1,785,827 | 1,782,441 | 1,780,233 | 1,778,792 | 1,776,803 | 21,470,623 | | |
| 4. Recoverable Costs Allocated to Demand | 34,105 | 34,071 | 34,038 | 34,005 | 33,971 | 33,939 | 33,905 | 33,872 | 33,841 | 33,805 | 33,772 | 33,741 | 407,065 | | |
| 5. Retail Energy Jurisdictional Factor | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | | | |
| 6. Retail Demand Jurisdictional Factor | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | | | |
| 7. Jurisdictional Energy Recoverable Costs (B) | 1,748,587 | 1,751,795 | 1,721,350 | 1,735,605 | 1,733,486 | 1,737,147 | 1,734,981 | 1,733,325 | 1,728,542 | 1,729,434 | 1,728,026 | 1,728,360 | 20,810,638 | | |
| 8. Jurisdictional Demand Recoverable Costs (C) | 32,548 | 32,516 | 32,485 | 32,453 | 32,421 | 32,390 | 32,358 | 32,326 | 32,297 | 32,262 | 32,231 | 32,201 | 388,488 | | |
| 9. Total Jurisdictional Recoverable Costs for | $1,781,135 | $1,784,311 | $1,753,835 | $1,768,058 | $1,765,907 | $1,769,537 | $1,767,339 | $1,765,651 | $1,760,839 | $1,761,696 | $1,760,257 | $1,760,561 | $21,199,126 | | |



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
DOCUMENT NO. 7
PAGE 1 OF 1
FORM 42-7A
FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | |
| 3. | Less: Accumulated Depreciation | (1,719,897) | (1,739,123) | (1,758,349) | (1,777,575) | (1,796,801) | (1,816,027) | (1,835,253) | (1,854,479) | (1,873,705) | (1,892,931) | (1,912,157) | (1,931,383) | (1,950,609) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $6,519,761 | 6,500,535 | 6,481,309 | 6,462,083 | 6,442,857 | 6,423,631 | 6,404,405 | 6,385,179 | 6,365,953 | 6,346,727 | 6,327,501 | 6,308,275 | 6,289,049 | |
| 6. | Average Net Investment | | 6,510,148 | 6,490,922 | 6,471,696 | 6,452,470 | 6,433,244 | 6,414,018 | 6,394,792 | 6,375,566 | 6,356,340 | 6,337,114 | 6,317,888 | 6,298,662 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 47,870 | 47,729 | 47,587 | 47,446 | 47,305 | 47,163 | 47,022 | 46,881 | 46,739 | 46,598 | 46,456 | 46,315 | $565,111 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 15,299 | 15,254 | 15,208 | 15,163 | 15,118 | 15,073 | 15,028 | 14,983 | 14,937 | 14,892 | 14,847 | 14,802 | 180,604 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 230,712 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | 82,395 | 82,209 | 82,021 | 81,835 | 81,649 | 81,462 | 81,276 | 81,090 | 80,902 | 80,716 | 80,529 | 80,343 | 976,427 |
| | a. Recoverable Costs Allocated to Energy | | 82,395 | 82,209 | 82,021 | 81,835 | 81,649 | 81,462 | 81,276 | 81,090 | 80,902 | 80,716 | 80,529 | 80,343 | 976,427 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9696203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 79,898 | 79,974 | 78,621 | 79,208 | 78,936 | 78,988 | 78,823 | 78,706 | 78,456 | 78,413 | 78,231 | 78,153 | 948,407 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $79,898 | $79,974 | $78,621 | $79,208 | $78,936 | $78,988 | $78,823 | $78,706 | $78,456 | $78,413 | $78,231 | $78,153 | $948,407 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



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DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
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FORM 42-8A
FILED: APRIL 1, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Cleanngs to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $5,017,734 | $5,017,734 | $5,017,734 | $5,017,734 | $5,017,734 | $5,017,734 | $5,017,734 | $5,017,734 | $5,017,734 | $5,017,734 | $5,017,734 | $5,017,734 | $5,017,734 | |
| 3. | Less: Accumulated Depreciation | (1,423,454) | (1,439,790) | (1,456,126) | (1,472,462) | (1,488,798) | (1,505,134) | (1,521,470) | (1,537,806) | (1,554,142) | (1,570,478) | (1,586,814) | (1,603,150) | (1,619,486) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $3,594,280 | 3,577,944 | 3,561,608 | 3,545,272 | 3,528,936 | 3,512,600 | 3,496,264 | 3,479,928 | 3,463,592 | 3,447,256 | 3,430,920 | 3,414,584 | 3,398,248 | |
| 6. | Average Net Investment | | 3,586,112 | 3,569,776 | 3,553,440 | 3,537,104 | 3,520,768 | 3,504,432 | 3,488,096 | 3,471,760 | 3,455,424 | 3,439,088 | 3,422,752 | 3,406,416 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 26,369 | 26,249 | 26,129 | 26,009 | 25,889 | 25,769 | 25,649 | 25,528 | 25,408 | 25,288 | 25,168 | 25,048 | $308,503 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 8,427 | 8,389 | 8,351 | 8,312 | 8,274 | 8,235 | 8,197 | 8,159 | 8,120 | 8,082 | 8,043 | 8,005 | 98,594 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 196,032 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | 51,132 | 50,974 | 50,816 | 50,657 | 50,499 | 50,340 | 50,182 | 50,023 | 49,864 | 49,706 | 49,547 | 49,389 | 603,129 |
| | a. Recoverable Costs Allocated to Energy | | 51,132 | 50,974 | 50,816 | 50,657 | 50,499 | 50,340 | 50,182 | 50,023 | 49,864 | 49,706 | 49,547 | 49,389 | 603,129 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 49,583 | 49,588 | 48,710 | 49,031 | 48,821 | 48,811 | 48,668 | 48,552 | 48,356 | 48,288 | 48,133 | 48,042 | 584,583 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $49,583 | $49,588 | $48,710 | $49,031 | $48,821 | $48,811 | $48,668 | $48,552 | $48,356 | $48,288 | $48,133 | $48,042 | $584,583 |

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 and 312.42
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rates are 4.0% and 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



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DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-8A
FILED: APRIL 1, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend 4 Continuous Emissions Monitor
(in Dollars)

| Line | Description | Beginning of Period Amoun | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $866,211 | $866,211 | $866,211 | $866,211 | $866,211 | $866,211 | $866,211 | $866,211 | $866,211 | $866,211 | $866,211 | $866,211 | $866,211 | |
| 3. | Less: Accumulated Depreciation | (191,333) | (193,282) | (195,231) | (197,180) | (199,129) | (201,078) | (203,027) | (204,976) | (206,925) | (208,874) | (210,823) | (212,772) | (214,721) | |
| 4. | Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $674,878 | 672,929 | 670,980 | 669,031 | 667,082 | 665,133 | 663,184 | 661,235 | 659,286 | 657,337 | 655,388 | 653,439 | 651,490 | |
| 6. | Average Net Investment | | 673,904 | 671,955 | 670,006 | 668,057 | 666,108 | 664,159 | 662,210 | 660,261 | 658,312 | 656,363 | 654,414 | 652,465 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 4,955 | 4,941 | 4,927 | 4,912 | 4,898 | 4,884 | 4,869 | 4,855 | 4,841 | 4,826 | 4,812 | 4,798 | $58,518 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,584 | 1,579 | 1,575 | 1,570 | 1,565 | 1,561 | 1,556 | 1,552 | 1,547 | 1,542 | 1,538 | 1,533 | 18,702 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 23,388 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | 8,488 | 8,469 | 8,451 | 8,431 | 8,412 | 8,394 | 8,374 | 8,356 | 8,337 | 8,317 | 8,299 | 8,280 | 100,608 |
| | a. Recoverable Costs Allocated to Energy | | 8,488 | 8,469 | 8,451 | 8,431 | 8,412 | 8,394 | 8,374 | 8,356 | 8,337 | 8,317 | 8,299 | 8,280 | 100,608 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 8,231 | 8,239 | 8,101 | 8,160 | 8,132 | 8,139 | 8,121 | 8,110 | 8,085 | 8,080 | 8,062 | 8,054 | 97,514 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $8,231 | $8,239 | $8,101 | $8,160 | $8,132 | $8,139 | $8,121 | $8,110 | $8,085 | $8,080 | $8,062 | $8,054 | $97,514 |

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.7%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 9b x Line 11



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TAMPA ELECTRIC COMPANY
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FORM 42-8A
FILED: APRIL 1, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Gannon Ignition Oil Tank
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $589,752 | $589,752 | $589,752 | $589,752 | $589,752 | $589,752 | $589,752 | $589,752 | $589,752 | $589,752 | $589,752 | $589,752 | $589,752 | |
| 3. | Less: Accumulated Depreciation | (371,852) | (390,010) | (408,168) | (426,327) | (444,485) | (462,643) | (480,801) | (498,959) | (517,117) | (535,276) | (553,434) | (571,593) | (589,752) | |
| 4. | CWIP - Non-Interest Bearing | 0 | | | | | | | | | | | | | |
| | 4a. Other (B) | (266,000) | (266,000) | (266,000) | (266,000) | (266,000) | (266,000) | (266,000) | (266,000) | (266,000) | (266,000) | (266,000) | (266,000) | (266,000) | |
| 5. | Net Investment (Lines 2 + 3 + 4) (C) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 6. | Average Net Investment | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $0 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (E) | | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,159 | 18,159 | 217,900 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,159 | 18,159 | 217,898 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,158 | 18,159 | 18,159 | 217,898 |
| 10. | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (G) | | 17,329 | 17,329 | 17,329 | 17,329 | 17,329 | 17,329 | 17,329 | 17,329 | 17,329 | 17,329 | 17,330 | 17,330 | 207,950 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $17,329 | $17,329 | $17,329 | $17,329 | $17,329 | $17,329 | $17,329 | $17,329 | $17,329 | $17,329 | $17,330 | $17,330 | $207,950 |

Notes:
(A) The depreciable base for Gannon; account 312.50
(B) Represents the Capital Costs of the Gannon Ignition Oil Tank currently recovered through base rates.
(C) From the beginning of the period forward, the net investment is zero due to the sum of the accumulated depreciation and other costs (currently recovered through base rates) being greater than plant in service. Therefore, no return on investment is calculated. For future months only the depreciation is recovered.
(D) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(E) Asset depreciation was accelerated to achieve full depreciation by year-end 2003. This coincides with commercial operation of Bayside Power Station.
(F) Line 9a x Line 10
(G) Line 9b x Line 11



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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank #1 Upgrade
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1. Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | 2. Plant-in-Service/Depreciation Base (A) | $497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | |
| | 3. Less: Accumulated Depreciation | (55,504) | (56,624) | (57,744) | (58,864) | (59,984) | (61,104) | (62,224) | (63,344) | (64,464) | (65,584) | (66,704) | (67,824) | (68,944) | |
| | 4. CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | 5. Net Investment (Lines 2 + 3 + 4) | $442,074 | 440,954 | 439,834 | 438,714 | 437,594 | 436,474 | 435,354 | 434,234 | 433,114 | 431,994 | 430,874 | 429,754 | 428,634 | |
| | 6. Average Net Investment | | 441,514 | 440,394 | 439,274 | 438,154 | 437,034 | 435,914 | 434,794 | 433,674 | 432,554 | 431,434 | 430,314 | 429,194 | |
| | 7. Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 3,247 | 3,238 | 3,230 | 3,222 | 3,214 | 3,205 | 3,197 | 3,189 | 3,181 | 3,172 | 3,164 | 3,156 | $38,415 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,038 | 1,035 | 1,032 | 1,030 | 1,027 | 1,024 | 1,022 | 1,019 | 1,017 | 1,014 | 1,011 | 1,009 | 12,278 |
| | 8. Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 13,440 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 9. Total System Recoverable Expenses (Lines 7 +8) | | 5,405 | 5,393 | 5,382 | 5,372 | 5,361 | 5,349 | 5,339 | 5,328 | 5,318 | 5,306 | 5,295 | 5,285 | 64,133 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 5,405 | 5,393 | 5,382 | 5,372 | 5,361 | 5,349 | 5,339 | 5,328 | 5,318 | 5,306 | 5,295 | 5,285 | 64,133 |
| | 10. Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| | 11. Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| | 12. Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 13. Retail Demand-Related Recoverable Costs (E) | | 5,158 | 5,147 | 5,136 | 5,127 | 5,116 | 5,105 | 5,095 | 5,085 | 5,075 | 5,064 | 5,053 | 5,044 | 61,205 |
| | 14. Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $5,158 | $5,147 | $5,136 | $5,127 | $5,116 | $5,105 | $5,095 | $5,085 | $5,075 | $5,064 | $5,053 | $5,044 | $61,205 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.7%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



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FILED: APRIL 1, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank #2 Upgrade
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | |
| 3. | Less: Accumulated Depreciation | (91,324) | (93,165) | (95,006) | (96,847) | (98,688) | (100,529) | (102,370) | (104,211) | (106,052) | (107,893) | (109,734) | (111,575) | (113,416) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $727,077 | 725,236 | 723,395 | 721,554 | 719,713 | 717,872 | 716,031 | 714,190 | 712,349 | 710,508 | 708,667 | 706,826 | 704,985 | |
| 6. | Average Net Investment | | 726,157 | 724,316 | 722,475 | 720,634 | 718,793 | 716,952 | 715,111 | 713,270 | 711,429 | 709,588 | 707,747 | 705,906 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 5,340 | 5,326 | 5,312 | 5,299 | 5,285 | 5,272 | 5,258 | 5,245 | 5,231 | 5,218 | 5,204 | 5,191 | $63,181 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,706 | 1,702 | 1,698 | 1,693 | 1,689 | 1,685 | 1,681 | 1,676 | 1,672 | 1,668 | 1,663 | 1,659 | 20,192 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 22,092 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | 8,887 | 8,869 | 8,851 | 8,833 | 8,815 | 8,798 | 8,780 | 8,762 | 8,744 | 8,727 | 8,708 | 8,691 | 105,465 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 8,887 | 8,869 | 8,851 | 8,833 | 8,815 | 8,798 | 8,780 | 8,762 | 8,744 | 8,727 | 8,708 | 8,691 | 105,465 |
| 10. | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 8,481 | 8,464 | 8,447 | 8,430 | 8,413 | 8,396 | 8,379 | 8,362 | 8,345 | 8,329 | 8,311 | 8,294 | 100,651 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $8,481 | $8,464 | $8,447 | $8,430 | $8,413 | $8,396 | $8,379 | $8,362 | $8,345 | $8,329 | $8,311 | $8,294 | $100,651 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.7%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
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FORM 42-8A
FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank #1 for FDEP
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | |
| 3. | Less: Accumulated Depreciation | (9,528) | (9,709) | (9,890) | (10,071) | (10,252) | (10,433) | (10,614) | (10,795) | (10,976) | (11,157) | (11,338) | (11,519) | (11,700) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $47,749 | 47,568 | 47,387 | 47,206 | 47,025 | 46,844 | 46,663 | 46,482 | 46,301 | 46,120 | 45,939 | 45,758 | 45,577 | |
| 6. | Average Net Investment | | 47,659 | 47,478 | 47,297 | 47,116 | 46,935 | 46,754 | 46,573 | 46,392 | 46,211 | 46,030 | 45,849 | 45,668 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 350 | 349 | 348 | 346 | 345 | 344 | 342 | 341 | 340 | 338 | 337 | 338 | $4,118 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 112 | 112 | 111 | 111 | 110 | 110 | 109 | 109 | 109 | 108 | 108 | 107 | 1,316 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 2,172 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | 643 | 642 | 640 | 638 | 636 | 635 | 632 | 631 | 630 | 627 | 626 | 624 | 7,604 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 643 | 642 | 640 | 638 | 636 | 635 | 632 | 631 | 630 | 627 | 626 | 624 | 7,604 |
| 10. | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 614 | 613 | 611 | 609 | 607 | 606 | 603 | 602 | 601 | 598 | 597 | 596 | 7,257 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $614 | $613 | $611 | $609 | $607 | $606 | $603 | $602 | $601 | $598 | $597 | $596 | $7,257 |

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
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FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank #4 for FDEP
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | |
| 3. | Less: Accumulated Depreciation | (15,479) | (15,765) | (16,051) | (16,337) | (16,623) | (16,909) | (17,195) | (17,481) | (17,767) | (18,053) | (18,339) | (18,625) | (18,911) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $74,993 | 74,707 | 74,421 | 74,135 | 73,849 | 73,563 | 73,277 | 72,991 | 72,705 | 72,419 | 72,133 | 71,847 | 71,561 | |
| 6. | Average Net Investment | | 74,850 | 74,564 | 74,278 | 73,992 | 73,706 | 73,420 | 73,134 | 72,848 | 72,562 | 72,276 | 71,990 | 71,704 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 550 | 548 | 546 | 544 | 542 | 540 | 538 | 536 | 534 | 531 | 529 | 527 | $6,465 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 176 | 175 | 175 | 174 | 173 | 173 | 172 | 171 | 171 | 170 | 169 | 169 | 2,068 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 3,432 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | 1,012 | 1,009 | 1,007 | 1,004 | 1,001 | 999 | 996 | 993 | 991 | 987 | 984 | 982 | 11,965 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 1,012 | 1,009 | 1,007 | 1,004 | 1,001 | 999 | 996 | 993 | 991 | 987 | 984 | 982 | 11,965 |
| 10. | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 966 | 963 | 961 | 958 | 955 | 953 | 951 | 948 | 946 | 942 | 939 | 937 | 11,419 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $966 | $963 | $961 | $958 | $955 | $953 | $951 | $948 | $946 | $942 | $939 | $937 | $11,419 |

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
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FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Gannon Unit 5 Classifier Replacement
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (A) | $1,357,040 | $1,357,040 | $1,357,040 | $1,357,040 | $1,357,040 | $1,357,040 | $1,357,040 | $1,357,040 | $1,357,040 | $1,357,040 | $1,357,040 | $1,357,040 | $1,357,040 | |
| 3 | Less: Accumulated Depreciation | (858,348) | (899,906) | (941,463) | (983,021) | (1,024,579) | (1,066,136) | (1,107,694) | (1,149,252) | (1,190,809) | (1,232,367) | (1,273,925) | (1,315,482) | (1,357,040) | |
| 4 | Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $498,692 | 457,134 | 415,577 | 374,019 | 332,461 | 290,904 | 249,346 | 207,788 | 166,231 | 124,673 | 83,115 | 41,558 | 0 | |
| 6 | Average Net Investment | | 477,913 | 436,356 | 394,798 | 353,240 | 311,683 | 270,125 | 228,567 | 187,010 | 145,452 | 103,894 | 62,336 | 20,779 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 3,514 | 3,209 | 2,903 | 2,597 | 2,292 | 1,986 | 1,681 | 1,375 | 1,070 | 764 | 458 | 153 | $22,002 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,123 | 1,025 | 928 | 830 | 732 | 635 | 537 | 439 | 342 | 244 | 146 | 49 | 7,030 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 41,558 | 41,558 | 41,558 | 41,558 | 41,558 | 41,558 | 41,558 | 41,558 | 41,558 | 41,558 | 41,558 | 41,558 | 498,692 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 46,195 | 45,792 | 45,389 | 44,985 | 44,582 | 44,179 | 43,776 | 43,372 | 42,970 | 42,566 | 42,162 | 41,760 | 527,728 |
| | a. Recoverable Costs Allocated to Energy | | 46,195 | 45,792 | 45,389 | 44,985 | 44,582 | 44,179 | 43,776 | 43,372 | 42,970 | 42,566 | 42,162 | 41,760 | 527,728 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11 | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (D) | | 44,795 | 44,547 | 43,508 | 43,541 | 43,100 | 42,837 | 42,455 | 42,097 | 41,671 | 41,351 | 40,959 | 40,621 | 511,482 |
| 13 | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $44,795 | $44,547 | $43,508 | $43,541 | $43,100 | $42,837 | $42,455 | $42,097 | $41,671 | $41,351 | $40,959 | $40,621 | $511,482 |

Notes:
(A) The depreciable base was adjusted to reflect the remaining net book value that existed when the five-year amortization schedule was implemented. The depreciable base for Gannon; account 312.55
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Asset depreciation was accelerated to achieve full depreciation by year-end 2003. This coincides with commercial operation of Bayside Power Station.
(D) Line 9a x Line 10
(E) Line 9b x Line 11



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**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Gannon Unit 6 Classifier Replacement
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (A) | $1,418,424 | $1,418,424 | $1,418,424 | $1,418,424 | $1,418,424 | $1,418,424 | $1,418,424 | $1,418,424 | $1,418,424 | $1,418,424 | $1,418,424 | $1,418,424 | $1,418,424 | |
| 3 | Less: Accumulated Depreciation | (860,530) | (907,020) | (953,510) | (1,000,000) | (1,046,490) | (1,092,980) | (1,139,470) | (1,185,960) | (1,232,450) | (1,278,940) | (1,325,430) | (1,371,920) | (1,418,424) | |
| 4 | Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | | $557,894 | 511,404 | 464,914 | 418,424 | 371,934 | 325,444 | 278,954 | 232,464 | 185,974 | 139,484 | 92,994 | 46,504 | 0 | |
| 6 | Average Net Investment | | 534,649 | 488,159 | 441,669 | 395,179 | 348,689 | 302,199 | 255,709 | 209,219 | 162,729 | 116,239 | 69,749 | 23,252 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 3,931 | 3,590 | 3,248 | 2,906 | 2,564 | 2,222 | 1,880 | 1,538 | 1,197 | 855 | 513 | 171 | $24,615 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,256 | 1,147 | 1,038 | 929 | 819 | 710 | 601 | 492 | 382 | 273 | 164 | 55 | 7,866 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 46,490 | 46,490 | 46,490 | 46,490 | 46,490 | 46,490 | 46,490 | 46,490 | 46,490 | 46,490 | 46,490 | 46,504 | 557,894 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 51,677 | 51,227 | 50,776 | 50,325 | 49,873 | 49,422 | 48,971 | 48,520 | 48,069 | 47,618 | 47,167 | 46,730 | 590,375 |
| | a. Recoverable Costs Allocated to Energy | | 51,677 | 51,227 | 50,776 | 50,325 | 49,873 | 49,422 | 48,971 | 48,520 | 48,069 | 47,618 | 47,167 | 46,730 | 590,375 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | |
| 11 | Demand Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| | | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (D) | | 50,111 | 49,835 | 48,671 | 48,709 | 48,216 | 47,921 | 47,493 | 47,094 | 46,615 | 46,259 | 45,821 | 45,456 | 572,201 |
| 13 | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $50,111 | $49,835 | $48,671 | $48,709 | $48,216 | $47,921 | $47,493 | $47,094 | $46,615 | $46,259 | $45,821 | $45,456 | $572,201 |

Notes:
(A) The depreciable base was adjusted to reflect the remaining net book value that existed when the five-year amortization schedule was implemented. Applicable depreciable base for Gannon; account 312.55
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Asset depreciation was accelerated to achieve full depreciation by year-end 2003. This coincides with commercial operation of Bayside Power Station.
(D) Line 9a x Line 10
(E) Line 9b x Line 11



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TAMPA ELECTRIC COMPANY
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**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (A) | $1,316,257 | $1,316,257 | $1,316,257 | $1,316,257 | $1,316,257 | $1,316,257 | $1,316,257 | $1,316,257 | $1,316,257 | $1,316,257 | $1,316,257 | $1,316,257 | $1,316,257 | |
| 3 | Less: Accumulated Depreciation | (186,008) | (190,396) | (194,784) | (199,172) | (203,560) | (207,948) | (212,336) | (216,724) | (221,112) | (225,500) | (229,888) | (234,276) | (238,664) | |
| 4 | Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $1,130,249 | 1,125,861 | 1,121,473 | 1,117,085 | 1,112,697 | 1,108,309 | 1,103,921 | 1,099,533 | 1,095,145 | 1,090,757 | 1,086,369 | 1,081,981 | 1,077,593 | |
| 6 | Average Net Investment | | 1,128,055 | 1,123,667 | 1,119,279 | 1,114,891 | 1,110,503 | 1,106,115 | 1,101,727 | 1,097,339 | 1,092,951 | 1,088,563 | 1,084,175 | 1,079,787 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 8,295 | 8,263 | 8,230 | 8,198 | 8,166 | 8,133 | 8,101 | 8,069 | 8,037 | 8,004 | 7,972 | 7,940 | $97,408 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 2,651 | 2,641 | 2,630 | 2,620 | 2,610 | 2,599 | 2,589 | 2,579 | 2,568 | 2,558 | 2,548 | 2,537 | 31,130 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 52,656 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 15,334 | 15,292 | 15,248 | 15,206 | 15,164 | 15,120 | 15,078 | 15,036 | 14,993 | 14,950 | 14,908 | 14,865 | 181,194 |
| | a. Recoverable Costs Allocated to Energy | | 15,334 | 15,292 | 15,248 | 15,206 | 15,164 | 15,120 | 15,078 | 15,036 | 14,993 | 14,950 | 14,908 | 14,865 | 181,194 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11 | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (D) | | 14,869 | 14,876 | 14,616 | 14,718 | 14,660 | 14,661 | 14,623 | 14,594 | 14,540 | 14,523 | 14,483 | 14,460 | 175,623 |
| 13 | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $14,869 | $14,876 | $14,616 | $14,718 | $14,660 | $14,661 | $14,623 | $14,594 | $14,540 | $14,523 | $14,483 | $14,460 | $175,623 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 4.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
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FORM 42-8A
FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (A) | $984,794 | $984,794 | $984,794 | $984,794 | $984,794 | $984,794 | $984,794 | $984,794 | $984,794 | $984,794 | $984,794 | $984,794 | $984,794 | |
| 3 | Less: Accumulated Depreciation | (149,070) | (152,189) | (155,308) | (158,427) | (161,546) | (164,665) | (167,784) | (170,903) | (174,022) | (177,141) | (180,260) | (183,379) | (186,498) | |
| 4 | Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $835,724 | 832,605 | 829,486 | 826,367 | 823,248 | 820,129 | 817,010 | 813,891 | 810,772 | 807,653 | 804,534 | 801,415 | 798,296 | |
| 6 | Average Net Investment | | 834,165 | 831,046 | 827,927 | 824,808 | 821,689 | 818,570 | 815,451 | 812,332 | 809,213 | 806,094 | 802,975 | 799,856 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 6,134 | 6,111 | 6,088 | 6,065 | 6,042 | 6,019 | 5,996 | 5,973 | 5,950 | 5,927 | 5,904 | 5,881 | $72,090 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,960 | 1,953 | 1,946 | 1,938 | 1,931 | 1,924 | 1,916 | 1,909 | 1,902 | 1,894 | 1,887 | 1,880 | 23,040 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 37,428 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 11,213 | 11,183 | 11,153 | 11,122 | 11,092 | 11,062 | 11,031 | 11,001 | 10,971 | 10,940 | 10,910 | 10,880 | 132,558 |
| | a. Recoverable Costs Allocated to Energy | | 11,213 | 11,183 | 11,153 | 11,122 | 11,092 | 11,062 | 11,031 | 11,001 | 10,971 | 10,940 | 10,910 | 10,880 | 132,558 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11 | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (D) | | 10,873 | 10,879 | 10,691 | 10,765 | 10,723 | 10,726 | 10,698 | 10,678 | 10,639 | 10,628 | 10,599 | 10,583 | 128,482 |
| 13 | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $10,873 | $10,879 | $10,691 | $10,765 | $10,723 | $10,726 | $10,698 | $10,678 | $10,639 | $10,628 | $10,599 | $10,583 | $128,482 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



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DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
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FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 200 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Gannon Coal Crusher ($NO_x$ Control)
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (A) | $5,227,289 | $5,227,289 | $5,227,289 | $5,227,289 | $5,227,289 | $5,227,289 | $5,227,289 | $5,227,289 | $5,227,289 | $5,227,289 | $5,227,289 | $5,227,289 | $5,227,289 | |
| 3 | Less: Accumulated Depreciation | (3,178,195) | (3,348,953) | (3,519,711) | (3,690,469) | (3,861,227) | (4,031,985) | (4,202,743) | (4,373,501) | (4,544,259) | (4,715,017) | (4,885,775) | (5,056,533) | (5,227,289) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $2,049,094 | 1,878,336 | 1,707,578 | 1,536,820 | 1,366,062 | 1,195,304 | 1,024,546 | 853,788 | 683,030 | 512,272 | 341,514 | 170,756 | 0 | |
| 6 | Average Net Investment | | 1,963,715 | 1,792,957 | 1,622,199 | 1,451,441 | 1,280,683 | 1,109,925 | 939,167 | 768,409 | 597,651 | 426,893 | 256,135 | 85,378 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 14,440 | 13,184 | 11,928 | 10,673 | 9,417 | 8,161 | 6,906 | 5,650 | 4,395 | 3,139 | 1,883 | 628 | $90,404 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 4,615 | 4,213 | 3,812 | 3,411 | 3,010 | 2,608 | 2,207 | 1,806 | 1,404 | 1,003 | 602 | 201 | 28,892 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 170,758 | 170,758 | 170,758 | 170,758 | 170,758 | 170,758 | 170,758 | 170,758 | 170,758 | 170,758 | 170,758 | 170,756 | 2,049,094 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 189,813 | 188,155 | 186,498 | 184,842 | 183,185 | 181,527 | 179,871 | 178,214 | 176,557 | 174,900 | 173,243 | 171,585 | 2,168,390 |
| | a. Recoverable Costs Allocated to Energy | | 189,813 | 188,155 | 186,498 | 184,842 | 183,185 | 181,527 | 179,871 | 178,214 | 176,557 | 174,900 | 173,243 | 171,585 | 2,168,390 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11 | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (D) | | 184,062 | 183,041 | 178,768 | 178,908 | 177,097 | 176,013 | 174,443 | 172,975 | 171,218 | 169,909 | 168,299 | 166,907 | 2,101,640 |
| 13 | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $184,062 | $183,041 | $178,768 | $178,908 | $177,097 | $176,013 | $174,443 | $172,975 | $171,218 | $169,909 | $168,299 | $168,907 | $2,101,640 |

Notes:

(A) The depreciable base was adjusted to reflect the remaining net book value that existed when the five-year amortization schedule was implemented. Applicable depreciable base for Gannon; account 312.55

(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).

(C) Asset depreciation was accelerated to achieve full depreciation by year-end 2003. This coincides with commercial operation of Bayside Power Station.

(D) Line 9a x Line 10

(E) Line 9b x Line 11



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DOCKET NO. 040007-EI
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**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (A) | $120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | |
| 3 | Less: Accumulated Depreciation | (7,615) | (7,856) | (8,097) | (8,338) | (8,579) | (8,820) | (9,061) | (9,302) | (9,543) | (9,784) | (10,025) | (10,266) | (10,507) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $113,122 | 112,881 | 112,640 | 112,399 | 112,158 | 111,917 | 111,676 | 111,435 | 111,194 | 110,953 | 110,712 | 110,471 | 110,230 | |
| 6 | Average Net Investment | | 113,002 | 112,761 | 112,520 | 112,279 | 112,038 | 111,797 | 111,556 | 111,315 | 111,074 | 110,833 | 110,592 | 110,351 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 831 | 829 | 827 | 826 | 824 | 822 | 820 | 819 | 817 | 815 | 813 | 811 | $9,854 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 266 | 265 | 264 | 264 | 263 | 263 | 262 | 262 | 261 | 260 | 260 | 259 | 3,149 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 2,892 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 1,338 | 1,335 | 1,332 | 1,331 | 1,328 | 1,326 | 1,323 | 1,322 | 1,319 | 1,316 | 1,314 | 1,311 | 15,895 |
| | a. Recoverable Costs Allocated to Energy | | 1,338 | 1,335 | 1,332 | 1,331 | 1,328 | 1,326 | 1,323 | 1,322 | 1,319 | 1,316 | 1,314 | 1,311 | 15,895 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11 | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (D) | | 1,297 | 1,299 | 1,277 | 1,288 | 1,284 | 1,286 | 1,283 | 1,283 | 1,279 | 1,278 | 1,276 | 1,275 | 15,405 |
| 13 | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $1,297 | $1,299 | $1,277 | $1,288 | $1,284 | $1,286 | $1,283 | $1,283 | $1,279 | $1,278 | $1,276 | $1,275 | $15,405 |

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
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FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (A) | $83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | |
| 3 | Less: Accumulated Depreciation | (11,073,435) | (11,364,389) | (11,655,343) | (11,946,297) | (12,237,251) | (12,528,205) | (12,819,159) | (13,110,113) | (13,401,067) | (13,692,021) | (13,982,975) | (14,273,929) | (14,564,883) | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $72,056,286 | 71,765,332 | 71,474,378 | 71,183,424 | 70,892,470 | 70,601,516 | 70,310,562 | 70,019,608 | 69,728,654 | 69,437,700 | 69,146,746 | 68,855,792 | 68,564,838 | |
| 6 | Average Net Investment | | 71,910,809 | 71,619,855 | 71,328,901 | 71,037,947 | 70,746,993 | 70,456,039 | 70,165,085 | 69,874,131 | 69,583,177 | 69,292,223 | 69,001,269 | 68,710,315 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 528,772 | 526,633 | 524,493 | 522,354 | 520,214 | 518,075 | 515,936 | 513,796 | 511,657 | 509,517 | 507,378 | 505,238 | $6,204,063 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 168,990 | 168,307 | 167,623 | 166,939 | 166,255 | 165,572 | 164,888 | 164,204 | 163,520 | 162,837 | 162,153 | 161,469 | 1,982,757 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 3,491,448 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 988,716 | 985,894 | 983,070 | 980,247 | 977,423 | 974,601 | 971,778 | 968,954 | 966,131 | 963,308 | 960,485 | 957,661 | 11,678,268 |
| | a. Recoverable Costs Allocated to Energy | | 988,716 | 985,894 | 983,070 | 980,247 | 977,423 | 974,601 | 971,778 | 968,954 | 966,131 | 963,308 | 960,485 | 957,661 | 11,678,268 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11 | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (D) | | 958,757 | 959,097 | 942,324 | 948,779 | 944,941 | 944,999 | 942,450 | 940,467 | 936,916 | 935,820 | 933,073 | 931,551 | 11,319,174 |
| 13 | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $958,757 | $959,097 | $942,324 | $948,779 | $944,941 | $944,999 | $942,450 | $940,467 | $936,916 | $935,820 | $933,073 | $931,551 | $11,319,174 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 4.2%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO.
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
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FORM 42-8A
FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (A) | $21,739,737 | $21,739,737 | $21,739,737 | $21,739,737 | $21,739,737 | $21,739,737 | $21,739,737 | $21,739,737 | $21,739,737 | $21,739,737 | $21,739,737 | $21,739,737 | $21,739,737 | |
| 3 | Less: Accumulated Depreciation | (599,161) | (649,857) | (700,553) | (751,249) | (801,945) | (852,641) | (903,337) | (954,033) | (1,004,729) | (1,055,425) | (1,106,121) | (1,156,817) | (1,207,513) | |
| 4 | CWIP - Non-Interest Bearing | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (B) | $21,140,576 | 21,089,880 | 21,039,184 | 20,988,488 | 20,937,792 | 20,887,096 | 20,836,400 | 20,785,704 | 20,735,008 | 20,684,312 | 20,633,616 | 20,582,920 | 20,532,224 | |
| 6 | Average Net Investment | | 21,115,228 | 21,064,532 | 21,013,836 | 20,963,140 | 20,912,444 | 20,861,748 | 20,811,052 | 20,760,356 | 20,709,660 | 20,658,964 | 20,608,268 | 20,557,572 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (C) | | 155,264 | 154,891 | 154,518 | 154,145 | 153,773 | 153,400 | 153,027 | 152,654 | 152,282 | 151,909 | 151,536 | 151,163 | $1,838,562 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 49,621 | 49,502 | 49,383 | 49,263 | 49,144 | 49,025 | 48,906 | 48,787 | 48,668 | 48,549 | 48,429 | 48,310 | 587,587 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 608,352 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 255,581 | 255,089 | 254,597 | 254,104 | 253,613 | 253,121 | 252,629 | 252,137 | 251,648 | 251,154 | 250,661 | 250,169 | 3,034,501 |
| | a. Recoverable Costs Allocated to Energy | | 255,581 | 255,089 | 254,597 | 254,104 | 253,613 | 253,121 | 252,629 | 252,137 | 251,646 | 251,154 | 250,661 | 250,169 | 3,034,501 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11 | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | 247,837 | 248,155 | 244,045 | 245,947 | 245,185 | 245,433 | 245,005 | 244,724 | 244,036 | 243,987 | 243,507 | 243,348 | 2,941,209 |
| 13 | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $247,837 | $248,155 | $244,045 | $245,947 | $245,185 | $245,433 | $245,005 | $244,724 | $244,036 | $243,987 | $243,507 | $243,348 | $2,941,209 |

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.45 and 312.46
(B) Net investment is comprised of several projects having various depreciation rates.
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(D) Applicable depreciation rates are 2.1% and 2.8%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
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FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend PM Minimization and Monitoring
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $70,325 | $160,174 | ($532,230) | $261,855 | $111,063 | $232,053 | $20,885 | $30,357 | ($150,616) | $7,256 | $70,310 | $60,412 | $341,845 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (A) | $247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | |
| 3 | Less: Accumulated Depreciation | (11,990) | (12,671) | (13,352) | (14,033) | (14,714) | (15,395) | (16,076) | (16,757) | (17,438) | (18,119) | (18,800) | (19,481) | (20,162) | |
| 4 | CWIP - Non-Interest Bearing | 5,871,081 | 5,941,406 | 6,101,580 | 5,569,350 | 5,831,206 | 5,942,269 | 6,174,322 | 6,195,207 | 6,225,564 | 6,074,948 | 6,082,204 | 6,152,514 | 6,212,926 | |
| 5 | Net Investment (Lines 2 + 3 + 4) (B) | $6,106,269 | 6,175,913 | 6,335,406 | 5,802,495 | 6,063,670 | 6,174,052 | 6,405,424 | 6,425,628 | 6,455,304 | 6,304,007 | 6,310,582 | 6,380,211 | 6,439,942 | |
| 6 | Average Net Investment | | 6,141,091 | 6,255,660 | 6,068,951 | 5,933,083 | 6,118,861 | 6,289,738 | 6,415,526 | 6,440,466 | 6,379,655 | 6,307,294 | 6,345,396 | 6,410,076 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (C) | | 45,156 | 45,999 | 44,626 | 43,627 | 44,993 | 46,249 | 47,174 | 47,358 | 46,911 | 46,379 | 46,659 | 47,134 | $552,265 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 14,432 | 14,701 | 14,262 | 13,943 | 14,379 | 14,781 | 15,076 | 15,135 | 14,992 | 14,822 | 14,912 | 15,064 | 176,499 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 681 | 681 | 681 | 681 | 681 | 681 | 681 | 681 | 681 | 681 | 681 | 681 | 8,172 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 60,269 | 61,381 | 59,569 | 58,251 | 60,053 | 61,711 | 62,931 | 63,174 | 62,584 | 61,882 | 62,252 | 62,879 | 736,936 |
| | a. Recoverable Costs Allocated to Energy | | 60,269 | 61,381 | 59,569 | 58,251 | 60,053 | 61,711 | 62,931 | 63,174 | 62,584 | 61,882 | 62,252 | 62,879 | 736,936 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11 | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | 58,443 | 59,713 | 57,100 | 56,381 | 58,057 | 59,837 | 61,032 | 61,317 | 60,692 | 60,116 | 60,475 | 61,165 | 714,328 |
| 13 | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $58,443 | $59,713 | $57,100 | $56,381 | $58,057 | $59,837 | $61,032 | $61,317 | $60,692 | $60,116 | $60,475 | $61,165 | $714,328 |

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.40 and 312.43
(B) Net investment is comprised of several projects having various depreciation rates.
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(D) Applicable depreciation rates are 3.4% and 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
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FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend $NO_x$ Emissions Reduction
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $251,829 | $108,497 | $49,748 | $89,741 | $134,967 | $29,104 | $67,887 | $128,677 | $158,930 | $109,560 | $66,208 | ($230,618) | $964,530 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (A) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 3 | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | CWIP - Non-Interest Bearing | 3,848,559 | 4,100,388 | 4,208,885 | 4,258,633 | 4,348,374 | 4,483,340 | 4,512,444 | 4,580,332 | 4,709,009 | 4,867,939 | 4,977,499 | 5,043,707 | 4,813,089 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $3,848,559 | 4,100,388 | 4,208,885 | 4,258,633 | 4,348,374 | 4,483,340 | 4,512,444 | 4,580,332 | 4,709,009 | 4,867,939 | 4,977,499 | 5,043,707 | 4,813,089 | |
| 6 | Average Net Investment | | 3,974,474 | 4,154,637 | 4,233,759 | 4,303,503 | 4,415,857 | 4,497,892 | 4,546,388 | 4,644,670 | 4,788,474 | 4,922,719 | 5,010,603 | 4,928,398 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 29,225 | 30,550 | 31,132 | 31,644 | 32,471 | 33,074 | 33,430 | 34,153 | 35,210 | 36,198 | 36,844 | 36,239 | $400,170 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 9,340 | 9,763 | 9,949 | 10,113 | 10,377 | 10,570 | 10,684 | 10,915 | 11,253 | 11,568 | 11,775 | 11,582 | 127,889 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 38,565 | 40,313 | 41,081 | 41,757 | 42,848 | 43,644 | 44,114 | 45,068 | 46,463 | 47,766 | 48,619 | 47,821 | 528,059 |
| | a. Recoverable Costs Allocated to Energy | | 38,565 | 40,313 | 41,081 | 41,757 | 42,848 | 43,644 | 44,114 | 45,068 | 46,463 | 47,766 | 48,619 | 47,821 | 528,059 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11 | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (D) | | 37,396 | 39,217 | 39,378 | 40,416 | 41,424 | 42,318 | 42,783 | 43,743 | 45,058 | 46,403 | 47,231 | 46,517 | 511,884 |
| 13 | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $37,396 | $39,217 | $39,378 | $40,416 | $41,424 | $42,318 | $42,783 | $43,743 | $45,058 | $46,403 | $47,231 | $46,517 | $511,884 |

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 and 312.42
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rates are 4.0% and 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



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DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
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FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Polk $NO_x$ Emissions Reduction
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $55,175 | $134,186 | $350,284 | $485,350 | $130,068 | $51,887 | $55,671 | $18,947 | $22,355 | $13,874 | $1,066 | $3,504 | $1,322,367 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (A) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 3 | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | CWIP - Non-Interest Bearing | 231,116 | 286,291 | 420,477 | 770,761 | 1,256,111 | 1,386,179 | 1,438,066 | 1,493,737 | 1,512,684 | 1,535,039 | 1,548,913 | 1,549,979 | 1,553,483 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $231,116 | 286,291 | 420,477 | 770,761 | 1,256,111 | 1,386,179 | 1,438,066 | 1,493,737 | 1,512,684 | 1,535,039 | 1,548,913 | 1,549,979 | 1,553,483 | |
| 6 | Average Net Investment | | 258,704 | 353,384 | 595,619 | 1,013,436 | 1,321,145 | 1,412,123 | 1,465,902 | 1,503,211 | 1,523,862 | 1,541,976 | 1,549,446 | 1,551,731 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 1,902 | 2,598 | 4,380 | 7,452 | 9,715 | 10,384 | 10,779 | 11,053 | 11,205 | 11,338 | 11,393 | 11,410 | $103,609 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 608 | 830 | 1,400 | 2,382 | 3,105 | 3,318 | 3,445 | 3,533 | 3,581 | 3,624 | 3,641 | 3,647 | 33,114 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 2,510 | 3,428 | 5,780 | 9,834 | 12,820 | 13,702 | 14,224 | 14,586 | 14,786 | 14,962 | 15,034 | 15,057 | 136,723 |
| | a. Recoverable Costs Allocated to Energy | | 2,510 | 3,428 | 5,780 | 9,834 | 12,820 | 13,702 | 14,224 | 14,586 | 14,786 | 14,962 | 15,034 | 15,057 | 136,723 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11 | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (E) | | 2,434 | 3,335 | 5,540 | 9,518 | 12,394 | 13,286 | 13,795 | 14,157 | 14,339 | 14,535 | 14,605 | 14,646 | 132,584 |
| 13 | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $2,434 | $3,335 | $5,540 | $9,518 | $12,394 | $13,286 | $13,795 | $14,157 | $14,339 | $14,535 | $14,605 | $14,646 | $132,584 |

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
DOCUMENT NO. 8
PAGE 19 OF 21
FORM 42-8A
FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $50,000 | $9,611 | $283,454 | $17,573 | $303,904 | $82,605 | $594,137 | $133,285 | $776,149 | $2,250,718 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (A) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 3 | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 50,000 | 59,611 | 343,065 | 360,638 | 664,542 | 747,147 | 1,341,284 | 1,474,569 | 2,250,718 | |
| 5 | Net Investment (Lines 2 + 3 + 4) | $0 | 0 | 0 | 0 | 50,000 | 59,611 | 343,065 | 360,638 | 664,542 | 747,147 | 1,341,284 | 1,474,569 | 2,250,718 | |
| 6 | Average Net Investment | | 0 | 0 | 0 | 25,000 | 54,806 | 201,338 | 351,852 | 512,590 | 705,845 | 1,044,216 | 1,407,927 | 1,862,644 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 0 | 0 | 0 | 184 | 403 | 1,480 | 2,587 | 3,769 | 5,190 | 7,678 | 10,353 | 13,696 | $45,340 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 0 | 0 | 0 | 59 | 129 | 473 | 827 | 1,205 | 1,659 | 2,454 | 3,309 | 4,377 | 14,492 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 0 | 0 | 0 | 243 | 532 | 1,953 | 3,414 | 4,974 | 6,849 | 10,132 | 13,662 | 18,073 | 59,832 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 243 | 532 | 1,953 | 3,414 | 4,974 | 6,849 | 10,132 | 13,662 | 18,073 | 59,832 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11 | Demand Junsdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 235 | 514 | 1,894 | 3,311 | 4,828 | 6,642 | 9,843 | 13,272 | 17,580 | 58,119 |
| 13 | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $0 | $0 | $0 | $235 | $514 | $1,894 | $3,311 | $4,828 | $6,642 | $9,843 | $13,272 | $17,580 | $58,119 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
DOCUMENT NO. 8
PAGE 20 OF 21
FORM 42-8A
FILED: APRIL 1, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
**January 2003 to December 2003**

For Project: $SO_2$ Emissions Allowances
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-03 | Actual Feb-03 | Actual Mar-03 | Actual Apr-03 | Actual May-03 | Actual Jun-03 | Actual Jul-03 | Actual Aug-03 | Actual Sep-03 | Actual Oct-03 | Actual Nov-03 | Actual Dec-03 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Purchases/Transfers | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b Sales/Transfers | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Auction Proceeds/Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Working Capital Balance | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | a FERC 158.1 Allowance Inventory | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b FERC 158.2 Allowances Withheld | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c FERC 182.3 Other Regl. Assets - Losses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d FERC 254 Regulatory Liabilities - Gains | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3 | Total Working Capital Balance | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4 | Average Net Working Capital Balance | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $0 |
| | b Debt Component (Line 6 x 2.82% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | Total Return Component | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Expenses: | | | | | | | | | | | | | | |
| | a Gains | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c SO2 Allowance Expense | | (159,799) | (22,333) | (141,032) | (83,796) | 288,456 | (30,008) | (15,714) | (6,410) | (52,802) | (14,501) | (1,510) | 24,500 | (214,949) |
| 8 | Net Expenses | | (159,799) | (22,333) | (141,032) | (83,796) | 288,456 | (30,008) | (15,714) | (6,410) | (52,802) | (14,501) | (1,510) | 24,500 | (214,949) |
| 9 | Total System Recoverable Expenses (Lines 6 + 7) | | (159,799) | (22,333) | (141,032) | (83,796) | 288,456 | (30,008) | (15,714) | (6,410) | (52,802) | (14,501) | (1,510) | 24,500 | (214,949) |
| | a Recoverable Costs Allocated to Energy | | (159,799) | (22,333) | (141,032) | (83,796) | 288,456 | (30,008) | (15,714) | (6,410) | (52,802) | (14,501) | (1,510) | 24,500 | (214,949) |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9696995 | 0.9728192 | 0.9585524 | 0.9678975 | 0.9667681 | 0.9696262 | 0.9698203 | 0.9706006 | 0.9697610 | 0.9714652 | 0.9714603 | 0.9727357 | |
| 11 | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12 | Retail Energy-Related Recoverable Costs (B) | | (154,957) | (21,726) | (135,187) | (81,106) | 278,870 | (29,097) | (15,240) | (6,222) | (51,205) | (14,087) | (1,467) | 23,832 | (207,592) |
| 13 | Retail Demand-Related Recoverable Costs (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | ($154,957) | ($21,726) | ($135,187) | ($81,106) | $278,870 | ($29,097) | ($15,240) | ($6,222) | ($51,205) | ($14,087) | ($1,467) | $23,832 | ($207,592) |

Notes:
(A) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(B) Line 9a x Line 10
(C) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
DOCUMENT NO. 8
PAGE 21 OF 21
FORM 42-8A
FILED: APRIL 1, 2004

EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
FILED: AUGUST 4, 2004

# ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

## JANUARY 2004 THROUGH DECEMBER 2004

## 42-1E THROUGH 42-8E



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040007-EI EXHIBIT NO. 12
COMPANY/ TECO
WITNESS: Howard T. Bryant (HTB-2)
DATE: 11-08-04

EXHIBIT NO._____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
FILED: AUGUST 4, 2004

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## ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

## JANUARY 2004 THROUGH DECEMBER 2004

## 42-1E THROUGH 42-8E


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**Tampa Electric Company** Form 42 - 1E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**
(in Dollars)

| Line | Period Amount |
|---|---|
| 1. Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5) | $7,076,962 |
| 2. Interest Provision (Form 42-2E, Line 6) | 57,699 |
| 3. Sum of Current Period Adjustments (Form 42-2E, Line 10) | 194,350 |
| 4. Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2004 to December 2004 (Lines 1 + 2 + 3) | $7,329,011 |

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EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 1
PAGE 1 OF 1
FORM 42-1E
FILED: AUGUST 4, 2004

Tampa Electric Company

Form 42 - 2E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

**Current Period True-Up Amount**
(in Dollars)

| Line | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. ECRC Revenues (net of Revenue Taxes) | $2,120,241 | $1,894,996 | $1,913,250 | $1,858,683 | $2,097,564 | $2,504,121 | $2,539,959 | $2,522,036 | $2,586,542 | $2,379,947 | $2,076,730 | $2,065,049 | $26,559,118 |
| 2. True-Up Provision | (51,698) | (51,698) | (51,698) | (51,698) | (51,698) | (51,698) | (51,698) | (51,698) | (51,698) | (51,698) | (51,698) | (51,698) | (620,371) |
| 3. ECRC Revenues Applicable to Period (Lines 1 + 2) | $2,068,543 | $1,843,298 | $1,861,552 | $1,806,985 | $2,045,866 | $2,452,423 | $2,488,261 | $2,470,338 | $2,534,844 | $2,328,249 | $2,025,032 | $2,013,351 | $25,938,747 |
| 4. Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| a. O & M Activities (Form 42-5E, Line 9) | 680,630 | 624,519 | 773,040 | 594,966 | 645,793 | 482,367 | (6,604,232) | 707,981 | 717,186 | 748,764 | 778,888 | 792,273 | 942,175 |
| b. Capital Investment Projects (Form 42-7E, Line 9) | 1,503,117 | 1,506,259 | 1,486,408 | 1,475,526 | 1,478,948 | 1,483,914 | 1,485,424 | 1,487,377 | 1,497,424 | 1,494,796 | 1,509,787 | 1,510,630 | 17,919,610 |
| c. Total Jurisdictional ECRC Costs | $2,183,747 | $2,130,778 | $2,259,448 | $2,070,492 | $2,124,741 | $1,966,281 | ($5,118,808) | $2,195,358 | $2,214,610 | $2,243,560 | $2,288,675 | $2,302,903 | $18,861,785 |
| 5. Over/Under Recovery (Line 3 - Line 4c) | (115,204) | (287,480) | (397,896) | (263,507) | (78,875) | 486,142 | 7,607,069 | 274,980 | 320,234 | 84,689 | (263,643) | (289,552) | 7,076,962 |
| 6. Interest Provision (Form 42-3E, Line 10) | (625) | (729) | (951) | (1,210) | (1,342) | (1,294) | 3,878 | 11,334 | 11,936 | 12,381 | 12,338 | 11,983 | 57,699 |
| 7. Beginning Balance True-Up & Interest Provision | (620,371) | (490,152) | (726,663) | (1,073,812) | (1,286,831) | (1,315,350) | (778,804) | 6,883,841 | 7,221,853 | 7,605,721 | 7,754,489 | 7,554,882 | (620,371) |
| a. Deferred True-Up from January to December 2003 (Order No. PSC-xx-xxxx-FOF-EI) | (260,351) | (260,351) | (260,351) | (260,351) | (260,351) | (260,351) | (260,351) | (260,351) | (260,351) | (260,351) | (260,351) | (260,351) | (260,351) |
| 8. True-Up Collected/(Refunded) (see Line 2) | 51,698 | 51,698 | 51,698 | 51,698 | 51,698 | 51,698 | 51,698 | 51,698 | 51,698 | 51,698 | 51,698 | 51,698 | 620,371 |
| 9. End of Period Total True-Up (Lines 5 + 6 + 7 +7a + 8) | (944,853) | (987,014) | (1,334,163) | (1,547,182) | (1,575,701) | (1,039,155) | 6,623,490 | 6,961,502 | 7,345,370 | 7,494,138 | 7,294,531 | 7,068,660 | 6,874,310 |
| 10. Adjustment to Period True-Up Including Interest | 194,350 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 194,350 |
| 11. End of Period Total Net True-Up (Lines 9 + 10) | ($750,503) | ($987,014) | ($1,334,163) | ($1,547,182) | ($1,575,701) | ($1,039,155) | $6,623,490 | $6,961,502 | $7,345,370 | $7,494,138 | $7,294,531 | $7,068,660 | $7,068,660 |



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 2
PAGE 1 OF 1
FORM 42-2E
FILED: AUGUST 4, 2004

Form 42 - 3E

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

**Interest Provision**
(in Dollars)

| Line | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. Beginning Balance True-Up Amount (Form 42-2E, Line 7 +7a + 10) | ($686,372) | ($750,503) | ($987,014) | ($1,334,163) | ($1,547,182) | ($1,575,701) | ($1,039,155) | $6,623,490 | $6,961,502 | $7,345,370 | $7,494,138 | $7,294,531 | |
| 2. Ending True-Up Amount Before Interest | (749,878) | (986,285) | (1,333,212) | (1,545,972) | (1,574,359) | (1,037,861) | 6,619,612 | 6,950,168 | 7,333,434 | 7,481,757 | 7,282,193 | 7,056,677 | |
| 3. Total of Beginning & Ending True-Up (Lines 1 & 2) | ($1,436,250) | ($1,736,788) | ($2,320,226) | ($2,880,135) | ($3,121,541) | ($2,613,562) | $5,580,457 | $13,573,658 | $14,294,936 | $14,827,127 | $14,776,331 | $14,351,208 | |
| 4. Average True-Up Amount (Line 3 x 1/2) | ($718,125) | ($868,394) | ($1,160,113) | ($1,440,068) | ($1,560,771) | ($1,306,781) | $2,790,229 | $6,786,829 | $7,147,468 | $7,413,564 | $7,388,166 | $7,175,604 | |
| 5. Interest Rate (First Day of Reporting Business Month) | 1.06% | 1.03% | 0.98% | 0.98% | 1.03% | 1.04% | 1.33% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | |
| 6. Interest Rate (First Day of Subsequent Business Month) | 1.03% | 0.98% | 0.98% | 1.03% | 1.04% | 1.33% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | |
| 7. Total of Beginning & Ending Interest Rates (Lines 5 & 6) | 2.09% | 2.01% | 1.96% | 2.01% | 2.07% | 2.37% | 3.33% | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% | |
| 8. Average Interest Rate (Line 7 x 1/2) | 1.045% | 1.005% | 0.980% | 1.005% | 1.035% | 1.185% | 1.665% | 2.000% | 2.000% | 2.000% | 2.000% | 2.000% | |
| 9. Monthly Average Interest Rate (Line 8 x 1/12) | 0.087% | 0.084% | 0.082% | 0.084% | 0.086% | 0.099% | 0.139% | 0.167% | 0.167% | 0.167% | 0.167% | 0.167% | |
| 10. Interest Provision for the Month (Line 4 x Line 9) | ($625) | ($729) | ($951) | ($1,210) | ($1,342) | ($1,294) | $3,878 | $11,334 | $11,936 | $12,381 | $12,338 | $11,983 | $57,699 |

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EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 3
PAGE 1 0F 1
FORM 42-3E
FILED: AUGUST 4, 2004

Form 42 - 4E

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

**Variance Report of O & M Activities**
(In Dollars)

| Line | | (1) Actual/ Estimated | (2) Original Projection | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1. | Description of O&M Activities | | | | |
| | 1a Big Bend Unit 3 Flue Gas Desulfurization Integration | $1,965,676 | $2,206,000 | ($240,324) | -10.9% |
| | 1b Big Bend Units 1 & 2 Flue Gas Conditioning | 0 | 0 | 0 | 0.0% |
| | 1c $SO_2$ Emissions Allowances | (7,608,085) | (220,100) | (7,387,985) | -3,356.6% |
| | 1d Big Bend Units 1 & 2 FGD | 4,774,156 | 4,288,700 | 485,456 | 11.3% |
| | 1e Big Bend PM Minimization and Monitoring | 1,000,484 | 980,000 | 20,484 | 2.1% |
| | 1f Big Bend $NO_x$ Emissions Reduction | 500,034 | 545,000 | (44,966) | -8.3% |
| | 1g NPDES Annual Surveillance Fees | 34,500 | 43,700 | (9,200) | -21.1% |
| | 1h Gannon Thermal Discharge Study | 152,526 | 250,000 | (97,474) | -39.0% |
| | 1i Polk $NO_x$ Emissions Reduction | 23,201 | 32,800 | (9,599) | -29.3% |
| | 1j Bayside SCR Consumables | 69,541 | 243,000 | (173,459) | -71.4% |
| | 1k Big Bend Unit 4 SOFA | 50,000 | 50,000 | 0 | 0.0% |
| 2. | Total Investment Projects - Recoverable Costs | $962,033 | $8,419,100 | ($7,457,067) | -88.6% |
| 3. | Recoverable Costs Allocated to Energy | $775,007 | $8,125,400 | ($7,350,393) | -3,463.0% |
| 4. | Recoverable Costs Allocated to Demand | $187,026 | $293,700 | ($106,674) | -36.3% |

Notes:
Column (1) is the End of Period Totals on Form 42-5E.
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 4
PAGE 1 OF 1
FORM 42-4E
FILED: AUGUST 4, 2004

Form 42 - 5E

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

**O&M Activities**
(in Dollars)

| Line | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. Description of O&M Activities | | | | | | | | | | | | | | | |
| 1a Big Bend Unit 3 Flue Gas Desulfurization Integration | $121,619 | $86,128 | $209,791 | $134,154 | $184,901 | $155,445 | $178,940 | $178,940 | $178,940 | $178,940 | $178,940 | $178,938 | $1,965,676 | | $1,965,676 |
| 1b Big Bend Units 1 & 2 Flue Gas Conditioning | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $0 | | 0 |
| 1c $SO_2$ Emissions Allowances | 6,211 | (98) | 2,574 | (8,318) | 2,456 | 4,679 | (7,505,619) | (25,638) | (22,706) | (19,172) | (18,207) | (24,247) | (7,608,085) | | (7,608,085) |
| 1d Big Bend Units 1 & 2 FGD (Less Gypsum Revenues) | 430,447 | 386,195 | 439,797 | 344,667 | 421,303 | 315,281 | 376,730 | 390,760 | 389,380 | 420,844 | 427,422 | 431,330 | 4,774,156 | | 4,774,156 |
| 1e Big Bend PM Minimization and Monitoring | 80,443 | 116,698 | 101,294 | 77,406 | 19,539 | 7,102 | 99,667 | 99,667 | 99,667 | 99,667 | 99,667 | 99,667 | 1,000,484 | | 1,000,484 |
| 1f Big Bend $NO_x$ Emissions Reduction | 21,103 | 38,852 | 36,022 | 68,036 | 32,279 | 8,742 | 49,000 | 49,000 | 49,000 | 49,000 | 49,000 | 50,000 | 500,034 | | 500,034 |
| 1g NPDES Annual Surveillance Fees | 34,500 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 34,500 | 34,500 | |
| 1h Gannon Thermal Discharge Study | 0 | 0 | 791 | 0 | 0 | 2,842 | 0 | 20,833 | 20,833 | 20,833 | 36,236 | 50,158 | 152,526 | 152,526 | |
| 1i Polk $NO_x$ Emissions Reduction | 1,584 | 2,662 | 1,580 | 1,717 | 1,582 | 2,933 | 1,857 | 1,857 | 1,857 | 1,857 | 1,857 | 1,858 | 23,201 | | 23,201 |
| 1j Bayside SCR Consumables | 0 | 6,458 | 6,034 | 0 | 6,293 | 0 | 8,459 | 8,459 | 8,459 | 8,459 | 8,459 | 8,461 | 69,541 | | 69,541 |
| 1k Big Bend Unit 4 SOFA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5,000 | 10,000 | 10,000 | 12,000 | 13,000 | 50,000 | | 50,000 |
| 2. Total of O&M Activities | $695,907 | $636,895 | $797,883 | $617,662 | $668,353 | $497,024 | ($6,790,966) | $728,878 | $735,430 | $770,428 | $795,374 | $809,165 | $962,033 | $187,026 | $775,007 |
| 3. Recoverable Costs Allocated to Energy | 661,407 | 636,895 | 797,092 | 617,662 | 668,353 | 494,182 | (6,790,966) | 708,045 | 714,597 | 749,595 | 759,138 | 759,007 | 775,007 | | |
| 4. Recoverable Costs Allocated to Demand | 34,500 | 0 | 791 | 0 | 0 | 2,842 | 0 | 20,833 | 20,833 | 20,833 | 36,236 | 50,158 | 187,026 | | |
| 5. Retail Energy Jurisdictional Factor | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | | | |
| 6. Retail Demand Jurisdictional Factor | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | | | |
| 7. Jurisdictional Energy Recoverable Costs (A) | 647,705 | 624,519 | 772,285 | 594,966 | 645,793 | 479,655 | (6,604,232) | 688,099 | 697,304 | 728,882 | 744,306 | 744,404 | 763,686 | | |
| 8. Jurisdictional Demand Recoverable Costs (B) | 32,925 | 0 | 755 | 0 | 0 | 2,712 | 0 | 19,882 | 19,882 | 19,882 | 34,582 | 47,869 | 178,489 | | |
| 9. Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $680,630 | $624,519 | $773,040 | $594,966 | $645,793 | $482,367 | ($6,604,232) | $707,981 | $717,186 | $748,764 | $778,888 | $792,273 | $942,175 | | |

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

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EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 5
PAGE 1 0F 1
FORM 42-5E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

**Variance Report of Capital Investment Projects - Recoverable Costs**
(In Dollars)

| Line | | (1) Actual/ Estimated | (2) Original Projection | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1. | Description of Investment Projects | | | | |
| 1a | Big Bend Unit 3 Flue Gas Desulfurization Integration | $949,565 | $949,565 | $0 | 0.0% |
| 1b | Big Bend Units 1 & 2 Flue Gas Conditioning | 580,305 | 580,305 | 0 | 0.0% |
| 1c | Big Bend Unit 4 Continuous Emissions Monitors | 97,884 | 97,884 | 0 | 0.0% |
| 1d | Big Bend Fuel Oil Tank #1 Upgrade | 62,567 | 62,567 | 0 | 0.0% |
| 1e | Big Bend Fuel Oil Tank #2 Upgrade | 102,893 | 102,893 | 0 | 0.0% |
| 1f | Phillips Upgrade Tank #1 for FDEP | 7,350 | 7,350 | 0 | 0.0% |
| 1g | Phillips Upgrade Tank #4 for FDEP | 11,563 | 11,563 | 0 | 0.0% |
| 1h | Big Bend Unit 1 Classifier Replacement | 175,064 | 175,064 | 0 | 0.0% |
| 1i | Big Bend Unit 2 Classifier Replacement | 128,202 | 128,202 | 0 | 0.0% |
| 1j | Big Bend Section 114 Mercury Testing Platform | 15,559 | 15,559 | 0 | 0.0% |
| 1k | Big Bend Units 1 & 2 FGD | 11,271,732 | 11,271,732 | 0 | 0.0% |
| 1l | Big Bend FGD Optimization and Utilization | 2,963,665 | 2,912,246 | 51,419 | 1.8% |
| 1m | Big Bend $NO_x$ Emissions Reduction | 620,346 | 605,009 | 15,337 | 2.5% |
| 1n | Big Bend PM Minimization and Monitoring | 848,091 | 915,233 | (67,142) | -7.3% |
| 1o | Polk $NO_x$ Emissions Reduction | 229,846 | 243,339 | (13,493) | -5.5% |
| 1p | Big Bend Unit 4 SOFA | 304,949 | 423,634 | (118,685) | -28.0% |
| 1q | Big Bend Unit 1 Pre-SCR | 11,354 | 0 | 11,354 | NA |
| 1r | Big Bend Unit 2 Pre-SCR | 16,325 | 0 | 16,325 | NA |
| 1s | Big Bend Unit 3 Pre-SCR | 12,713 | 0 | 12,713 | NA |
| 1t | Big Bend Unit 4 SCR | 0 | 0 | 0 | NA |
| 2. | Total Investment Projects - Recoverable Costs | $18,409,973 | $18,502,145 | ($92,172) | -0.5% |
| 3. | Recoverable Costs Allocated to Energy | $18,225,600 | $18,317,772 | ($92,172) | -0.5% |
| 4. | Recoverable Costs Allocated to Demand | $184,373 | $184,373 | $0 | 0.0% |

Notes:
Column (1) is the End of Period Totals on Form 42-7E.
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 6
PAGE 1 0F 1
FORM 42-6E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

**Capital Investment Projects-Recoverable Costs**
(in Dollars)

| Line | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. Description of Investment Projects (A) | | | | | | | | | | | | | | | |
| 1a Big Bend Unit 3 Flue Gas Desulfurization Integration | $80,157 | $79,969 | $79,783 | $79,597 | $79,410 | $79,224 | $79,038 | $78,850 | $78,664 | $78,477 | $78,291 | $78,105 | $949,565 | | $949,565 |
| 1b Big Bend Units 1 and 2 Flue Gas Conditioning | 49,231 | 49,072 | 48,914 | 48,755 | 48,596 | 48,438 | 48,279 | 48,121 | 47,963 | 47,804 | 47,646 | 47,486 | 580,305 | | 580,305 |
| 1c Big Bend Unit 4 Continuous Emissions Monitors | 8,261 | 8,242 | 8,224 | 8,204 | 8,185 | 8,167 | 8,147 | 8,129 | 8,110 | 8,090 | 8,072 | 8,053 | 97,884 | | 97,884 |
| 1d Big Bend Fuel Oil Tank #1 Upgrade | 5,274 | 5,262 | 5,252 | 5,241 | 5,230 | 5,220 | 5,208 | 5,198 | 5,187 | 5,176 | 5,165 | 5,154 | 62,567 | 62,567 | |
| 1e Big Bend Fuel Oil Tank #2 Upgrade | 8,673 | 8,655 | 8,637 | 8,619 | 8,601 | 8,583 | 8,566 | 8,547 | 8,530 | 8,512 | 8,494 | 8,476 | 102,893 | 102,893 | |
| 1f Phillips Upgrade Tank #1 for FDEP | 622 | 620 | 619 | 617 | 615 | 614 | 611 | 610 | 608 | 606 | 605 | 603 | 7,350 | 7,350 | |
| 1g Phillips Upgrade Tank #4 for FDEP | 979 | 976 | 973 | 971 | 968 | 965 | 963 | 959 | 956 | 954 | 951 | 948 | 11,563 | 11,563 | |
| 1h Big Bend Unit 1 Classifier Replacement | 14,823 | 14,780 | 14,738 | 14,695 | 14,653 | 14,610 | 14,567 | 14,525 | 14,482 | 14,439 | 14,397 | 14,355 | 175,064 | | 175,064 |
| 1i Big Bend Unit 2 Classifier Replacement | 10,850 | 10,820 | 10,790 | 10,759 | 10,729 | 10,699 | 10,668 | 10,638 | 10,608 | 10,577 | 10,547 | 10,517 | 128,202 | | 128,202 |
| 1j Big Bend Section 114 Mercury Testing Platform | 1,310 | 1,307 | 1,305 | 1,302 | 1,300 | 1,298 | 1,295 | 1,293 | 1,290 | 1,289 | 1,286 | 1,284 | 15,559 | | 15,559 |
| 1k Big Bend Units 1 & 2 FGD | 954,838 | 952,016 | 949,192 | 946,369 | 943,546 | 940,723 | 937,899 | 935,076 | 932,253 | 929,430 | 926,607 | 923,783 | 11,271,732 | | 11,271,732 |
| 1l Big Bend FGD Optimization and Utilization | 249,677 | 249,186 | 248,694 | 248,202 | 247,710 | 247,218 | 246,726 | 246,234 | 245,742 | 245,250 | 244,759 | 244,267 | 2,963,665 | | 2,963,665 |
| 1m Big Bend $NO_x$ Emissions Reduction | 47,033 | 47,787 | 48,701 | 49,940 | 50,872 | 51,237 | 51,995 | 52,910 | 53,589 | 54,446 | 55,590 | 56,246 | 620,346 | | 620,346 |
| 1n Big Bend PM Minimization and Monitoring | 64,407 | 66,822 | 67,949 | 68,081 | 68,452 | 68,817 | 69,527 | 70,572 | 72,558 | 75,266 | 77,330 | 78,310 | 848,091 | | 848,091 |
| 1o Polk $NO_x$ Emissions Reduction | 17,336 | 19,549 | 19,490 | 19,446 | 19,404 | 19,360 | 19,318 | 19,275 | 19,231 | 19,189 | 19,145 | 19,103 | 229,846 | | 229,846 |
| 1p Big Bend Unit 4 SOFA | 21,841 | 21,460 | 21,124 | 21,158 | 22,531 | 23,940 | 24,321 | 27,526 | 30,345 | 30,290 | 30,234 | 30,179 | 304,949 | | 304,949 |
| 1q Big Bend Unit 1 Pre-SCR | 0 | 0 | 0 | 0 | 0 | 0 | 243 | 801 | 1,456 | 2,159 | 2,935 | 3,760 | 11,354 | | 11,354 |
| 1r Big Bend Unit 2 Pre-SCR | 0 | 0 | 0 | 0 | 0 | 0 | 145 | 727 | 1,771 | 3,178 | 4,827 | 5,677 | 16,325 | | 16,325 |
| 1s Big Bend Unit 3 Pre-SCR | 0 | 0 | 0 | 0 | 0 | 0 | 194 | 776 | 1,553 | 2,426 | 3,397 | 4,367 | 12,713 | | 12,713 |
| 1t Big Bend Unit 4 SCR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| 2. Total Investment Projects - Recoverable Costs | $1,535,312 | $1,536,523 | $1,534,385 | $1,531,956 | $1,530,802 | $1,529,113 | $1,527,710 | $1,530,767 | $1,534,896 | $1,537,558 | $1,540,278 | $1,540,673 | $18,409,973 | $184,373 | $18,225,600 |
| 3. Recoverable Costs Allocated to Energy | 1,519,764 | 1,521,010 | 1,518,904 | 1,516,508 | 1,515,388 | 1,513,731 | 1,512,362 | 1,515,453 | 1,519,615 | 1,522,310 | 1,525,063 | 1,525,492 | $18,225,600 | | |
| 4. Recoverable Costs Allocated to Demand | 15,548 | 15,513 | 15,481 | 15,448 | 15,414 | 15,382 | 15,348 | 15,314 | 15,281 | 15,248 | 15,215 | 15,181 | 184,373 | | |
| 5. Retail Energy Jurisdictional Factor | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | | | |
| 6. Retail Demand Jurisdictional Factor | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | | | |
| 7. Jurisdictional Energy Recoverable Costs (B) | 1,488,279 | 1,491,454 | 1,471,634 | 1,460,783 | 1,464,237 | 1,469,234 | 1,470,776 | 1,472,762 | 1,482,840 | 1,480,244 | 1,495,266 | 1,496,142 | 17,743,651 | | |
| 8. Jurisdictional Demand Recoverable Costs (C) | 14,838 | 14,805 | 14,774 | 14,743 | 14,711 | 14,680 | 14,648 | 14,615 | 14,584 | 14,552 | 14,521 | 14,488 | 175,959 | | |
| 9. Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $1,503,117 | $1,506,259 | $1,486,408 | $1,475,526 | $1,478,948 | $1,483,914 | $1,485,424 | $1,487,377 | $1,497,424 | $1,494,796 | $1,509,787 | $1,510,630 | $17,919,610 | | |

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 7
PAGE 1 OF 1
FORM 42-7E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | |
| 3. | Less: Accumulated Depreciation | (1,950,609) | (1,969,835) | (1,989,061) | (2,008,287) | (2,027,513) | (2,046,739) | (2,065,965) | (2,085,191) | (2,104,417) | (2,123,643) | (2,142,869) | (2,162,095) | (2,181,321) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $6,289,049 | $6,269,823 | $6,250,597 | $6,231,371 | $6,212,145 | $6,192,919 | $6,173,693 | $6,154,467 | $6,135,241 | $6,116,015 | $6,096,789 | $6,077,563 | $6,058,337 | |
| 6. | Average Net Investment | | $6,279,436 | $6,260,210 | $6,240,984 | $6,221,758 | $6,202,532 | $6,183,306 | $6,164,080 | $6,144,854 | $6,125,628 | $6,106,402 | $6,087,176 | $6,067,950 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 46,174 | 46,032 | 45,891 | 45,750 | 45,608 | 45,467 | 45,326 | 45,184 | 45,043 | 44,901 | 44,760 | 44,619 | 544,755 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 14,757 | 14,711 | 14,666 | 14,621 | 14,576 | 14,531 | 14,486 | 14,440 | 14,395 | 14,350 | 14,305 | 14,260 | 174,098 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 230,712 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $80,157 | $79,969 | $79,783 | $79,597 | $79,410 | $79,224 | $79,038 | $78,850 | $78,664 | $78,477 | $78,291 | $78,105 | $949,565 |
| | a. Recoverable Costs Allocated to Energy | | 80,157 | 79,969 | 79,783 | 79,597 | 79,410 | 79,224 | 79,038 | 78,850 | 78,664 | 78,477 | 78,291 | 78,105 | 949,565 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 78,496 | 78,415 | 77,300 | 76,672 | 76,730 | 76,895 | 76,865 | 76,629 | 76,760 | 76,308 | 76,761 | 76,602 | 924,433 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $78,496 | $78,415 | $77,300 | $76,672 | $76,730 | $76,895 | $76,865 | $76,629 | $76,760 | $76,308 | $76,761 | $76,602 | $924,433 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 2.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 8
PAGE 1 OF 21
FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | .0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | |
| 3. | Less: Accumulated Depreciation | (1,619,486) | (1,635,822) | (1,652,158) | (1,668,494) | (1,684,830) | (1,701,166) | (1,717,502) | (1,733,838) | (1,750,174) | (1,766,510) | (1,782,846) | (1,799,182) | (1,815,518) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $3,398,248 | $3,381,912 | $3,365,576 | $3,349,240 | $3,332,904 | $3,316,568 | $3,300,232 | $3,283,896 | $3,267,560 | $3,251,224 | $3,234,888 | $3,218,552 | $3,202,216 | |
| 6. | Average Net Investment | | $3,390,080 | $3,373,744 | $3,357,408 | $3,341,072 | $3,324,736 | $3,308,400 | $3,292,064 | $3,275,728 | $3,259,392 | $3,243,056 | $3,226,720 | $3,210,384 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 24,928 | 24,808 | 24,688 | 24,567 | 24,447 | 24,327 | 24,207 | 24,087 | 23,967 | 23,847 | 23,727 | 23,606 | 291,206 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 7,967 | 7,928 | 7,890 | 7,852 | 7,813 | 7,775 | 7,736 | 7,698 | 7,660 | 7,621 | 7,583 | 7,544 | 93,067 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 196,032 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $49,231 | $49,072 | $48,914 | $48,755 | $48,596 | $48,438 | $48,279 | $48,121 | $47,963 | $47,804 | $47,646 | $47,486 | $580,305 |
| | a. Recoverable Costs Allocated to Energy | | 49,231 | 49,072 | 48,914 | 48,755 | 48,596 | 48,438 | 48,279 | 48,121 | 47,963 | 47,804 | 47,646 | 47,486 | 580,305 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 48,211 | 48,118 | 47,392 | 46,963 | 46,956 | 47,014 | 46,951 | 46,765 | 46,802 | 46,483 | 46,715 | 46,572 | 564,942 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $48,211 | $48,118 | $47,392 | $46,963 | $46,956 | $47,014 | $46,951 | $46,765 | $46,802 | $46,483 | $46,715 | $46,572 | $564,942 |

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 and 312.42
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rates are 4.0% and 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | |
| 3. | Less: Accumulated Depreciation | (214,721) | (216,670) | (218,619) | (220,568) | (222,517) | (224,466) | (226,415) | (228,364) | (230,313) | (232,262) | (234,211) | (236,160) | (238,109) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $651,490 | $649,541 | $647,592 | $645,643 | $643,694 | $641,745 | $639,796 | $637,847 | $635,898 | $633,949 | $632,000 | $630,051 | $628,102 | |
| 6. | Average Net Investment | | $650,516 | $648,567 | $646,618 | $644,669 | $642,720 | $640,771 | $638,822 | $636,873 | $634,924 | $632,975 | $631,026 | $629,077 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 4,783 | 4,769 | 4,755 | 4,740 | 4,726 | 4,712 | 4,697 | 4,683 | 4,669 | 4,654 | 4,640 | 4,626 | 56,454 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,529 | 1,524 | 1,520 | 1,515 | 1,510 | 1,506 | 1,501 | 1,497 | 1,492 | 1,487 | 1,483 | 1,478 | 18,042 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 23,388 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $8,261 | $8,242 | $8,224 | $8,204 | $8,185 | $8,167 | $8,147 | $8,129 | $8,110 | $8,090 | $8,072 | $8,053 | $97,884 |
| | a. Recoverable Costs Allocated to Energy | | 8,261 | 8,242 | 8,224 | 8,204 | 8,185 | 8,167 | 8,147 | 8,129 | 8,110 | 8,090 | 8,072 | 8,053 | 97,884 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 8,090 | 8,082 | 7,968 | 7,903 | 7,909 | 7,927 | 7,923 | 7,900 | 7,914 | 7,866 | 7,914 | 7,898 | 95,294 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $8,090 | $8,082 | $7,968 | $7,903 | $7,909 | $7,927 | $7,923 | $7,900 | $7,914 | $7,866 | $7,914 | $7,898 | $95,294 |

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 2.7%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank #1 Upgrade
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | |
| 3. | Less: Accumulated Depreciation | (68,944) | (70,064) | (71,184) | (72,304) | (73,424) | (74,544) | (75,664) | (76,784) | (77,904) | (79,024) | (80,144) | (81,264) | (82,384) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $428,634 | $427,514 | $426,394 | $425,274 | $424,154 | $423,034 | $421,914 | $420,794 | $419,674 | $418,554 | $417,434 | $416,314 | $415,194 | |
| 6. | Average Net Investment | | $428,074 | $426,954 | $425,834 | $424,714 | $423,594 | $422,474 | $421,354 | $420,234 | $419,114 | $417,994 | $416,874 | $415,754 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 3,148 | 3,139 | 3,131 | 3,123 | 3,115 | 3,107 | 3,098 | 3,090 | 3,082 | 3,074 | 3,065 | 3,057 | 37,229 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,006 | 1,003 | 1,001 | 998 | 995 | 993 | 990 | 988 | 985 | 982 | 980 | 977 | 11,898 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 13,440 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $5,274 | $5,262 | $5,252 | $5,241 | $5,230 | $5,220 | $5,208 | $5,198 | $5,187 | $5,176 | $5,165 | $5,154 | $62,567 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 5,274 | 5,262 | 5,252 | 5,241 | 5,230 | 5,220 | 5,208 | 5,198 | 5,187 | 5,176 | 5,165 | 5,154 | 62,567 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 5,033 | 5,022 | 5,012 | 5,002 | 4,991 | 4,982 | 4,970 | 4,961 | 4,950 | 4,940 | 4,929 | 4,919 | 59,711 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $5,033 | $5,022 | $5,012 | $5,002 | $4,991 | $4,982 | $4,970 | $4,961 | $4,950 | $4,940 | $4,929 | $4,919 | $59,711 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 2.7%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank #2 Upgrade
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | |
| 3 | Less: Accumulated Depreciation | (113,416) | (115,257) | (117,098) | (118,939) | (120,780) | (122,621) | (124,462) | (126,303) | (128,144) | (129,985) | (131,826) | (133,667) | (135,508) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $704,985 | $703,144 | $701,303 | $699,462 | $697,621 | $695,780 | $693,939 | $692,098 | $690,257 | $688,416 | $686,575 | $684,734 | $682,893 | |
| 6. | Average Net Investment | | $704,065 | $702,224 | $700,383 | $698,542 | $696,701 | $694,860 | $693,019 | $691,178 | $689,337 | $687,496 | $685,655 | $683,814 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 5,177 | 5,164 | 5,150 | 5,136 | 5,123 | 5,109 | 5,096 | 5,082 | 5,069 | 5,055 | 5,042 | 5,028 | 61,231 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,655 | 1,650 | 1,646 | 1,642 | 1,637 | 1,633 | 1,629 | 1,624 | 1,620 | 1,616 | 1,611 | 1,607 | 19,570 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 22,092 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $8,673 | $8,655 | $8,637 | $8,619 | $8,601 | $8,583 | $8,566 | $8,547 | $8,530 | $8,512 | $8,494 | $8,476 | $102,893 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 8,673 | 8,655 | 8,637 | 8,619 | 8,601 | 8,583 | 8,566 | 8,547 | 8,530 | 8,512 | 8,494 | 8,476 | 102,893 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 8,277 | 8,260 | 8,243 | 8,226 | 8,208 | 8,191 | 8,175 | 8,157 | 8,141 | 8,124 | 8,106 | 8,089 | 98,197 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $8,277 | $8,260 | $8,243 | $8,226 | $8,208 | $8,191 | $8,175 | $8,157 | $8,141 | $8,124 | $8,106 | $8,089 | $98,197 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 2.7%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



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FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank #1 for FDEP
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | |
| 3. | Less: Accumulated Depreciation | (11,700) | (11,881) | (12,062) | (12,243) | (12,424) | (12,605) | (12,786) | (12,967) | (13,148) | (13,329) | (13,510) | (13,691) | (13,872) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $45,577 | $45,396 | $45,215 | $45,034 | $44,853 | $44,672 | $44,491 | $44,310 | $44,129 | $43,948 | $43,767 | $43,586 | $43,405 | |
| 6. | Average Net Investment | | $45,487 | $45,306 | $45,125 | $44,944 | $44,763 | $44,582 | $44,401 | $44,220 | $44,039 | $43,858 | $43,677 | $43,496 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 334 | 333 | 332 | 330 | 329 | 328 | 326 | 325 | 324 | 322 | 321 | 320 | 3,924 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 107 | 106 | 106 | 106 | 105 | 105 | 104 | 104 | 103 | 103 | 103 | 102 | 1,254 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 2,172 |
| | b. Amortization | | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $622 | $620 | $619 | $617 | $615 | $614 | $611 | $610 | $608 | $606 | $605 | $603 | $7,350 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 622 | 620 | 619 | 617 | 615 | 614 | 611 | 610 | 608 | 606 | 605 | 603 | 7,350 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 594 | 592 | 591 | 589 | 587 | 586 | 583 | 582 | 580 | 578 | 577 | 575 | 7,014 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $594 | $592 | $591 | $589 | $587 | $586 | $583 | $582 | $580 | $578 | $577 | $575 | $7,014 |

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 8
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank #4 for FDEP
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | |
| 3. | Less: Accumulated Depreciation | (18,911) | (19,197) | (19,483) | (19,769) | (20,055) | (20,341) | (20,627) | (20,913) | (21,199) | (21,485) | (21,771) | (22,057) | (22,343) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $71,561 | $71,275 | $70,989 | $70,703 | $70,417 | $70,131 | $69,845 | $69,559 | $69,273 | $68,987 | $68,701 | $68,415 | $68,129 | |
| 6. | Average Net Investment | | $71,418 | $71,132 | $70,846 | $70,560 | $70,274 | $69,988 | $69,702 | $69,416 | $69,130 | $68,844 | $68,558 | $68,272 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 525 | 523 | 521 | 519 | 517 | 515 | 513 | 510 | 508 | 506 | 504 | 502 | 6,163 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 168 | 167 | 166 | 166 | 165 | 164 | 164 | 163 | 162 | 162 | 161 | 160 | 1,968 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 3,432 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $979 | $976 | $973 | $971 | $968 | $965 | $963 | $959 | $956 | $954 | $951 | $948 | $11,563 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 979 | 976 | 973 | 971 | 968 | 965 | 963 | 959 | 956 | 954 | 951 | 948 | 11,563 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 934 | 931 | 929 | 927 | 924 | 921 | 919 | 915 | 912 | 910 | 908 | 905 | 11,035 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $934 | $931 | $929 | $927 | $924 | $921 | $919 | $915 | $912 | $910 | $908 | $905 | $11,035 |

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | |
| 3. | Less: Accumulated Depreciation | (238,664) | (243,052) | (247,440) | (251,828) | (256,216) | (260,604) | (264,992) | (269,380) | (273,768) | (278,156) | (282,544) | (286,932) | (291,320) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,077,593 | 1,073,205 | 1,068,817 | 1,064,429 | 1,060,041 | 1,055,653 | 1,051,265 | 1,046,877 | 1,042,489 | 1,038,101 | 1,033,713 | 1,029,325 | 1,024,937 | |
| 6. | Average Net Investment | | $1,075,399 | $1,071,011 | $1,066,623 | $1,062,235 | $1,057,847 | $1,053,459 | $1,049,071 | $1,044,683 | $1,040,295 | $1,035,907 | $1,031,519 | $1,027,131 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 7,908 | 7,875 | 7,843 | 7,811 | 7,779 | 7,746 | 7,714 | 7,682 | 7,649 | 7,617 | 7,585 | 7,553 | 92,762 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 2,527 | 2,517 | 2,507 | 2,496 | 2,486 | 2,476 | 2,465 | 2,455 | 2,445 | 2,434 | 2,424 | 2,414 | 29,646 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 52,656 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $14,823 | $14,780 | $14,738 | $14,695 | $14,653 | $14,610 | $14,567 | $14,525 | $14,482 | $14,439 | $14,397 | $14,355 | $175,064 |
| | a. Recoverable Costs Allocated to Energy | | 14,823 | 14,780 | 14,738 | 14,695 | 14,653 | 14,610 | 14,567 | 14,525 | 14,482 | 14,439 | 14,397 | 14,355 | 175,064 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 14,516 | 14,493 | 14,279 | 14,155 | 14,158 | 14,181 | 14,166 | 14,116 | 14,132 | 14,040 | 14,116 | 14,079 | 170,431 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $14,516 | $14,493 | $14,279 | $14,155 | $14,158 | $14,181 | $14,166 | $14,116 | $14,132 | $14,040 | $14,116 | $14,079 | $170,431 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 4.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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EXHIBIT NO. _____
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TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | |
| 3. | Less: Accumulated Depreciation | (186,498) | (189,617) | (192,736) | (195,855) | (198,974) | (202,093) | (205,212) | (208,331) | (211,450) | (214,569) | (217,688) | (220,807) | (223,926) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $798,296 | $795,177 | $792,058 | $788,939 | $785,820 | $782,701 | $779,582 | $776,463 | $773,344 | $770,225 | $767,106 | $763,987 | $760,868 | |
| 6. | Average Net Investment | | $796,737 | $793,618 | $790,499 | $787,380 | $784,261 | $781,142 | $778,023 | $774,904 | $771,785 | $768,666 | $765,547 | $762,428 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 5,859 | 5,836 | 5,813 | 5,790 | 5,767 | 5,744 | 5,721 | 5,698 | 5,675 | 5,652 | 5,629 | 5,606 | 68,790 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,872 | 1,865 | 1,858 | 1,850 | 1,843 | 1,836 | 1,828 | 1,821 | 1,814 | 1,806 | 1,799 | 1,792 | 21,984 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 37,428 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $10,850 | $10,820 | $10,790 | $10,759 | $10,729 | $10,699 | $10,668 | $10,638 | $10,608 | $10,577 | $10,547 | $10,517 | $128,202 |
| | a. Recoverable Costs Allocated to Energy | | 10,850 | 10,820 | 10,790 | 10,759 | 10,729 | 10,699 | 10,668 | 10,638 | 10,608 | 10,577 | 10,547 | 10,517 | 128,202 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 10,625 | 10,610 | 10,454 | 10,364 | 10,367 | 10,384 | 10,375 | 10,338 | 10,351 | 10,285 | 10,341 | 10,315 | 124,809 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $10,625 | $10,610 | $10,454 | $10,364 | $10,367 | $10,384 | $10,375 | $10,338 | $10,351 | $10,285 | $10,341 | $10,315 | $124,809 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | |
| 3. | Less: Accumulated Depreciation | (10,507) | (10,748) | (10,989) | (11,230) | (11,471) | (11,712) | (11,953) | (12,194) | (12,435) | (12,676) | (12,917) | (13,158) | (13,399) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $110,230 | $109,989 | $109,748 | $109,507 | $109,266 | $109,025 | $108,784 | $108,543 | $108,302 | $108,061 | $107,820 | $107,579 | $107,338 | |
| 6. | Average Net Investment | | $110,110 | $109,869 | $109,628 | $109,387 | $109,146 | $108,905 | $108,664 | $108,423 | $108,182 | $107,941 | $107,700 | $107,459 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 810 | 808 | 806 | 804 | 803 | 801 | 799 | 797 | 795 | 794 | 792 | 790 | 9,599 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 259 | 258 | 258 | 257 | 256 | 256 | 255 | 255 | 254 | 254 | 253 | 253 | 3,068 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 2,892 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $1,310 | $1,307 | $1,305 | $1,302 | $1,300 | $1,298 | $1,295 | $1,293 | $1,290 | $1,289 | $1,286 | $1,284 | $15,559 |
| | a. Recoverable Costs Allocated to Energy | | 1,310 | 1,307 | 1,305 | 1,302 | 1,300 | 1,298 | 1,295 | 1,293 | 1,290 | 1,289 | 1,286 | 1,284 | 15,559 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 1,283 | 1,282 | 1,264 | 1,254 | 1,256 | 1,260 | 1,259 | 1,257 | 1,259 | 1,253 | 1,261 | 1,259 | 15,147 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $1,283 | $1,282 | $1,264 | $1,254 | $1,256 | $1,260 | $1,259 | $1,257 | $1,259 | $1,253 | $1,261 | $1,259 | $15,147 |

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 & 2 FGD
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | |
| 3. | Less: Accumulated Depreciation | (14,564,883) | (14,855,837) | (15,146,791) | (15,437,745) | (15,728,699) | (16,019,653) | (16,310,607) | (16,601,561) | (16,892,515) | (17,183,469) | (17,474,423) | (17,765,377) | (18,056,331) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $68,564,838 | $68,273,884 | $67,982,930 | $67,691,976 | $67,401,022 | $67,110,068 | $66,819,114 | $66,528,160 | $66,237,206 | $65,946,252 | $65,655,298 | $65,364,344 | $65,073,390 | |
| 6. | Average Net Investment | | $68,419,361 | $68,128,407 | $67,837,453 | $67,546,499 | $67,255,545 | $66,964,591 | $66,673,637 | $66,382,683 | $66,091,729 | $65,800,775 | $65,509,821 | $65,218,867 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 503,099 | 500,960 | 498,820 | 496,681 | 494,541 | 492,402 | 490,262 | 488,123 | 485,983 | 483,844 | 481,705 | 479,565 | 5,895,985 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 160,785 | 160,102 | 159,418 | 158,734 | 158,051 | 157,367 | 156,683 | 155,999 | 155,316 | 154,632 | 153,948 | 153,264 | 1,884,299 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 3,491,448 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $954,838 | $952,016 | $949,192 | $946,369 | $943,546 | $940,723 | $937,899 | $935,076 | $932,253 | $929,430 | $926,607 | $923,783 | $11,271,732 |
| | a. Recoverable Costs Allocated to Energy | | 954,838 | 952,016 | 949,192 | 946,369 | 943,546 | 940,723 | 937,899 | 935,076 | 932,253 | 929,430 | 926,607 | 923,783 | 11,271,732 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 935,057 | 933,516 | 919,652 | 911,594 | 911,697 | 913,070 | 912,109 | 908,734 | 909,692 | 903,747 | 908,503 | 906,009 | 10,973,380 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $935,057 | $933,516 | $919,652 | $911,594 | $911,697 | $913,070 | $912,109 | $908,734 | $909,692 | $903,747 | $908,503 | $906,009 | $10,973,380 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate 4.2%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | |
| 3. | Less: Accumulated Depreciation | (1,207,513) | (1,258,209) | (1,308,905) | (1,359,601) | (1,410,297) | (1,460,993) | (1,511,689) | (1,562,385) | (1,613,081) | (1,663,777) | (1,714,473) | (1,765,169) | (1,815,865) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) (B) | $20,532,224 | $20,481,528 | $20,430,832 | $20,380,136 | $20,329,440 | $20,278,744 | $20,228,048 | $20,177,352 | $20,126,656 | $20,075,960 | $20,025,264 | $19,974,568 | $19,923,872 | |
| 6. | Average Net Investment | | $20,506,876 | $20,456,180 | $20,405,484 | $20,354,788 | $20,304,092 | $20,253,396 | $20,202,700 | $20,152,004 | $20,101,308 | $20,050,612 | $19,999,916 | $19,949,220 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (C) | | 150,790 | 150,418 | 150,045 | 149,672 | 149,299 | 148,927 | 148,554 | 148,181 | 147,808 | 147,435 | 147,063 | 146,690 | 1,784,882 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 48,191 | 48,072 | 47,953 | 47,834 | 47,715 | 47,595 | 47,476 | 47,357 | 47,238 | 47,119 | 47,000 | 46,881 | 570,431 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 608,352 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $249,677 | $249,186 | $248,694 | $248,202 | $247,710 | $247,218 | $246,726 | $246,234 | $245,742 | $245,250 | $244,759 | $244,267 | $2,963,665 |
| | a. Recoverable Costs Allocated to Energy | | 249,677 | 249,186 | 248,694 | 248,202 | 247,710 | 247,218 | 246,726 | 246,234 | 245,742 | 245,250 | 244,759 | 244,267 | 2,963,665 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 244,504 | 244,344 | 240,954 | 239,082 | 239,349 | 239,951 | 239,942 | 239,297 | 239,795 | 238,473 | 239,977 | 239,567 | 2,885,235 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $244,504 | $244,344 | $240,954 | $239,082 | $239,349 | $239,951 | $239,942 | $239,297 | $239,795 | $238,473 | $239,977 | $239,567 | $2,885,235 |

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.45 and 312.45
(B) Net investment is comprised of several projects having various depreciation rates
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(D) Applicable depreciation rates are 2.1% and 2.8%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend $NO_x$ Emissions Reduction
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $68,065 | $87,463 | $100,925 | $154,500 | $37,516 | $37,658 | $118,640 | $70,000 | $70,000 | $106,534 | $129,514 | $5,651 | $986,466 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3. | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4. | CWIP - Non-Interest Bearing | 4,813,089 | 4,881,154 | 4,968,617 | 5,069,542 | 5,224,042 | 5,261,558 | 5,299,216 | 5,417,856 | 5,487,856 | 5,557,856 | 5,664,390 | 5,793,904 | 5,799,555 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $4,813,089 | $4,881,154 | $4,968,617 | $5,069,542 | $5,224,042 | $5,261,558 | $5,299,216 | $5,417,856 | $5,487,856 | $5,557,856 | $5,664,390 | $5,793,904 | $5,799,555 | |
| 6. | Average Net Investment | | $4,847,122 | $4,924,886 | $5,019,080 | $5,146,792 | $5,242,800 | $5,280,387 | $5,358,536 | $5,452,856 | $5,522,856 | $5,611,123 | $5,729,147 | $5,796,730 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 35,642 | 36,214 | 36,906 | 37,845 | 38,551 | 38,828 | 39,402 | 40,096 | 40,610 | 41,260 | 42,127 | 42,624 | 470,105 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 11,391 | 11,573 | 11,795 | 12,095 | 12,321 | 12,409 | 12,593 | 12,814 | 12,979 | 13,186 | 13,463 | 13,622 | 150,241 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $47,033 | $47,787 | $48,701 | $49,940 | $50,872 | $51,237 | $51,995 | $52,910 | $53,589 | $54,446 | $55,590 | $56,246 | $620,346 |
| | a. Recoverable Costs Allocated to Energy | | 47,033 | 47,787 | 48,701 | 49,940 | 50,872 | 51,237 | 51,995 | 52,910 | 53,589 | 54,446 | 55,590 | 56,246 | 620,346 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 46,059 | 46,858 | 47,185 | 48,105 | 49,155 | 49,731 | 50,565 | 51,419 | 52,292 | 52,942 | 54,504 | 55,164 | 603,979 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $46,059 | $46,858 | $47,185 | $48,105 | $49,155 | $49,731 | $50,565 | $51,419 | $52,292 | $52,942 | $54,504 | $55,164 | $603,979 |

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 and 312.42
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rates are 4.0% and 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend PM Minimization and Monitoring
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $242,438 | $256,897 | ($23,106) | $51,778 | $26,223 | $50,664 | $96,930 | $120,000 | $290,966 | $268,509 | $158,491 | $45,216 | $1,585,006 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | 247,178 | |
| 3. | Less: Accumulated Depreciation | (20,162) | (20,908) | (21,654) | (22,400) | (23,146) | (23,892) | (24,638) | (25,384) | (26,130) | (26,876) | (27,622) | (28,368) | (29,114) | |
| 4. | CWIP - Non-Interest Bearing | 6,212,926 | 6,455,364 | 6,712,261 | 6,689,155 | 6,740,933 | 6,767,156 | 6,817,820 | 6,914,750 | 7,034,750 | 7,325,716 | 7,594,225 | 7,752,716 | 7,797,932 | |
| 5. | Net Investment (Lines 2 + 3 + 4) (B) | $6,439,942 | $6,681,634 | $6,937,785 | $6,913,933 | $6,964,965 | $6,990,442 | $7,040,360 | $7,136,544 | $7,255,798 | $7,546,018 | $7,813,781 | $7,971,526 | $8,015,996 | |
| 6. | Average Net Investment | | $6,560,788 | $6,809,709 | $6,925,859 | $6,939,449 | $6,977,703 | $7,015,401 | $7,088,452 | $7,196,171 | $7,400,908 | $7,679,899 | $7,892,653 | $7,993,761 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (C) | | 48,243 | 50,073 | 50,927 | 51,027 | 51,308 | 51,585 | 52,123 | 52,915 | 54,420 | 56,472 | 58,036 | 58,779 | 635,908 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 15,418 | 16,003 | 16,276 | 16,308 | 16,398 | 16,486 | 16,658 | 16,911 | 17,392 | 18,048 | 18,548 | 18,785 | 203,231 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (D) | | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 8,952 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $64,407 | $66,822 | $67,949 | $68,081 | $68,452 | $68,817 | $69,527 | $70,572 | $72,558 | $75,266 | $77,330 | $78,310 | $848,091 |
| | a. Recoverable Costs Allocated to Energy | | 64,407 | 66,822 | 67,949 | 68,081 | 68,452 | 68,817 | 69,527 | 70,572 | 72,558 | 75,266 | 77,330 | 78,310 | 848,091 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (E) | | 63,073 | 65,524 | 65,834 | 65,579 | 66,141 | 66,794 | 67,615 | 68,584 | 70,802 | 73,186 | 75,819 | 76,803 | 825,754 |
| 13. | Retail Demand-Related Recoverable Costs (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $63,073 | $65,524 | $65,834 | $65,579 | $66,141 | $66,794 | $67,615 | $68,584 | $70,802 | $73,186 | $75,819 | $76,803 | $825,754 |

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 and 312.43
(B) Net investment is comprised of several projects having various depreciation rates.
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(D) Applicable depreciation rates are 4.0% and 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 8
PAGE 14 OF 21
FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Polk $NO_x$ Emissions Reduction
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $11,494 | ($3,504) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $7,990 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | 1,564,977 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | |
| 3. | Less: Accumulated Depreciation | 0 | (2,217) | (6,641) | (11,065) | (15,489) | (19,913) | (24,337) | (28,761) | (33,185) | (37,609) | (42,033) | (46,457) | (50,881) | |
| 4. | CWIP - Non-Interest Bearing | 1,553,483 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,553,483 | $1,562,760 | $1,554,832 | $1,550,408 | $1,545,984 | $1,541,560 | $1,537,136 | $1,532,712 | $1,528,288 | $1,523,864 | $1,519,440 | $1,515,016 | $1,510,592 | |
| 6. | Average Net Investment | | $1,558,122 | $1,558,796 | $1,552,620 | $1,548,196 | $1,543,772 | $1,539,348 | $1,534,924 | $1,530,500 | $1,526,076 | $1,521,652 | $1,517,228 | $1,512,804 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 11,457 | 11,462 | 11,417 | 11,384 | 11,352 | 11,319 | 11,287 | 11,254 | 11,221 | 11,189 | 11,156 | 11,124 | 135,622 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 3,662 | 3,663 | 3,649 | 3,638 | 3,628 | 3,617 | 3,607 | 3,597 | 3,586 | 3,576 | 3,565 | 3,555 | 43,343 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 2,217 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 50,881 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $17,336 | $19,549 | $19,490 | $19,446 | $19,404 | $19,360 | $19,318 | $19,275 | $19,231 | $19,189 | $19,145 | $19,103 | $229,846 |
| | a. Recoverable Costs Allocated to Energy | | 17,336 | 19,549 | 19,490 | 19,446 | 19,404 | 19,360 | 19,318 | 19,275 | 19,231 | 19,189 | 19,145 | 19,103 | 229,846 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 16,977 | 19,169 | 18,883 | 18,731 | 18,749 | 18,791 | 18,787 | 18,732 | 18,766 | 18,659 | 18,771 | 18,735 | 223,750 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $16,977 | $19,169 | $18,883 | $18,731 | $18,749 | $18,791 | $18,787 | $18,732 | $18,766 | $18,659 | $18,771 | $18,735 | $223,750 |

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $324 | ($78,813) | $9,555 | ($2,547) | $285,435 | $5,047 | $73,615 | $0 | $0 | $0 | $0 | $0 | $292,616 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,543,334 | 2,543,334 | 2,543,334 | 2,543,334 | 2,543,334 | |
| 3. | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | (0) | (0) | (2,862) | (8,585) | (14,308) | (20,031) | (25,754) | |
| 4. | CWIP - Non-Interest Bearing | 2,250,718 | 2,251,042 | 2,172,229 | 2,181,784 | 2,179,237 | 2,464,672 | 2,469,719 | 2,543,334 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $2,250,718 | 2,251,042 | 2,172,229 | 2,181,784 | 2,179,237 | 2,464,672 | 2,469,719 | 2,543,334 | 2,540,472 | 2,534,749 | 2,529,026 | 2,523,303 | 2,517,580 | |
| 6. | Average Net Investment | | $2,250,880 | $2,211,636 | $2,177,007 | $2,180,511 | $2,321,955 | $2,467,195 | $2,506,526 | $2,541,903 | $2,537,611 | $2,531,888 | $2,526,165 | $2,520,442 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 16,551 | 16,263 | 16,008 | 16,034 | 17,074 | 18,142 | 18,431 | 18,691 | 18,659 | 18,617 | 18,575 | 18,533 | 211,578 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 5,290 | 5,197 | 5,116 | 5,124 | 5,457 | 5,798 | 5,890 | 5,973 | 5,963 | 5,950 | 5,936 | 5,923 | 67,617 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,862 | 5,723 | 5,723 | 5,723 | 5,723 | 25,754 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $21,841 | $21,460 | $21,124 | $21,158 | $22,531 | $23,940 | $24,321 | $27,526 | $30,345 | $30,290 | $30,234 | $30,179 | $304,949 |
| | a. Recoverable Costs Allocated to Energy | | 21,841 | 21,460 | 21,124 | 21,158 | 22,531 | 23,940 | 24,321 | 27,526 | 30,345 | 30,290 | 30,234 | 30,179 | 304,949 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 21,389 | 21,043 | 20,467 | 20,381 | 21,770 | 23,236 | 23,652 | 26,751 | 29,611 | 29,453 | 29,643 | 29,598 | 296,994 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $21,389 | $21,043 | $20,467 | $20,381 | $21,770 | $23,236 | $23,652 | $26,751 | $29,611 | $29,453 | $29,643 | $29,598 | $296,994 |

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 2.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $50,000 | $65,000 | $70,000 | $75,000 | $85,000 | $85,000 | $430,000 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3. | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50,000 | 115,000 | 185,000 | 260,000 | 345,000 | 430,000 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $50,000 | $115,000 | $185,000 | $260,000 | $345,000 | $430,000 | |
| 6. | Average Net Investment | | $0 | $0 | $0 | $0 | $0 | $0 | $25,000 | $82,500 | $150,000 | $222,500 | $302,500 | $387,500 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 0 | 0 | 0 | 0 | 0 | 0 | 184 | 607 | 1,103 | 1,636 | 2,224 | 2,849 | 8,603 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 194 | 353 | 523 | 711 | 911 | 2,751 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $0 | $0 | $0 | $0 | $0 | $0 | $243 | $801 | $1,456 | $2,159 | $2,935 | $3,760 | $11,354 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 243 | 801 | 1,456 | 2,159 | 2,935 | 3,760 | 11,354 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 236 | 778 | 1,421 | 2,099 | 2,878 | 3,688 | 11,100 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $0 | $0 | $0 | $0 | $0 | $0 | $236 | $778 | $1,421 | $2,099 | $2,878 | $3,688 | $11,100 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $30,000 | $90,000 | $125,000 | $165,000 | $175,000 | $0 | $585,000 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3. | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 30,000 | 120,000 | 245,000 | 410,000 | 585,000 | 585,000 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 30,000 | 120,000 | 245,000 | 410,000 | 585,000 | 585,000 | |
| 6. | Average Net Investment | | $0 | $0 | $0 | $0 | $0 | $0 | $15,000 | $75,000 | $182,500 | $327,500 | $497,500 | $585,000 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 0 | 0 | 0 | 0 | 0 | 0 | 110 | 551 | 1,342 | 2,408 | 3,658 | 4,302 | 12,371 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 35 | 176 | 429 | 770 | 1,169 | 1,375 | 3,954 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $0 | $0 | $0 | $0 | $0 | $0 | $145 | $727 | $1,771 | $3,178 | $4,827 | $5,677 | $16,325 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 145 | 727 | 1,771 | 3,178 | 4,827 | 5,677 | 16,325 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 141 | 707 | 1,728 | 3,090 | 4,733 | 5,568 | 15,967 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $0 | $0 | $0 | $0 | $0 | $0 | $141 | $707 | $1,728 | $3,090 | $4,733 | $5,568 | $15,967 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 8
PAGE 18 OF 21
FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $40,000 | $80,000 | $80,000 | $100,000 | $100,000 | $100,000 | $500,000 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3. | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 40,000 | 120,000 | 200,000 | 300,000 | 400,000 | 500,000 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $40,000 | $120,000 | $200,000 | $300,000 | $400,000 | $500,000 | |
| 6. | Average Net Investment | | $0 | $0 | $0 | $0 | $0 | $0 | $20,000 | $80,000 | $160,000 | $250,000 | $350,000 | $450,000 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 0 | 0 | 0 | 0 | 0 | 0 | 147 | 588 | 1,177 | 1,838 | 2,574 | 3,309 | 9,633 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 47 | 188 | 376 | 588 | 823 | 1,058 | 3,080 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $0 | $0 | $0 | $0 | $0 | $0 | $194 | $776 | $1,553 | $2,426 | $3,397 | $4,367 | $12,713 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 194 | 776 | 1,553 | 2,426 | 3,397 | 4,367 | 12,713 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 189 | 754 | 1,515 | 2,359 | 3,331 | 4,283 | 12,431 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $0 | $0 | $0 | $0 | $0 | $0 | $189 | $754 | $1,515 | $2,359 | $3,331 | $4,283 | $12,431 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.8%
(E) Line 9a x Line 10
(F) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 8
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FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
**January 2004 to December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,450,000 | $550,000 | $576,000 | $3,576,000 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3. | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 6. | Average Net Investment | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) (G) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.



EXHIBIT NO.
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 8
PAGE 20 OF 21
FORM 42-8E
FILED: AUGUST 4, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
**January 2004 to December 2004**

For Project: $SO_2$ Emissions Allowances
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual Jan-04 | Actual Feb-04 | Actual Mar-04 | Actual Apr-04 | Actual May-04 | Actual Jun-04 | Estimated Jul-04 | Estimated Aug-04 | Estimated Sep-04 | Estimated Oct-04 | Estimated Nov-04 | Estimated Dec-04 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Purchases/Transfers | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Sales/Transfers | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Auction Proceeds/Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Working Capital Balance | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | a. FERC 158.1 Allowance Inventory | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b. FERC 158.2 Allowances Withheld | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. FERC 182.3 Other Regl. Assets - Losses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. FERC 254 Regulatory Liabilities - Gains | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3. | Total Working Capital Balance | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 4. | Average Net Working Capital Balance | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 5. | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6. | Total Return Component | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7. | Expenses: | | | | | | | | | | | | | | |
| | a. Gains | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. $SO_2$ Allowance Expense | | 6,211 | (98) | 2,574 | (8,318) | 2,456 | 4,679 | (7,505,619) | (25,638) | (22,706) | (19,172) | (18,207) | (24,247) | (7,608,085) |
| 8. | Net Expenses (B) | | 6,211 | (98) | 2,574 | (8,318) | 2,456 | 4,679 | (7,505,619) | (25,638) | (22,706) | (19,172) | (18,207) | (24,247) | (7,608,085) |
| 9. | Total System Recoverable Expenses (Lines 6 + 7) | | $6,211 | ($98) | $2,574 | ($8,318) | $2,456 | $4,679 | ($7,505,619) | ($25,638) | ($22,706) | ($19,172) | ($18,207) | ($24,247) | ($7,608,085) |
| | a. Recoverable Costs Allocated to Energy | | 6,211 | (98) | 2,574 | (8,318) | 2,456 | 4,679 | (7,505,619) | (25,638) | (22,706) | (19,172) | (18,207) | (24,247) | (7,608,085) |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9792832 | 0.9805679 | 0.9688786 | 0.9632544 | 0.9662456 | 0.9706043 | 0.9725026 | 0.9718295 | 0.9758000 | 0.9723673 | 0.9804619 | 0.9807600 | |
| 11. | Demand Jurisdictional Factor | | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | 0.9543611 | |
| 12. | Retail Energy-Related Recoverable Costs (C) | | 6,082 | (96) | 2,494 | (8,012) | 2,373 | 4,541 | (7,299,234) | (24,916) | (22,157) | (18,642) | (17,851) | (23,780) | (7,399,198) |
| 13. | Retail Demand-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Juris. Recoverable Costs (Lines 12 + 13) | | $6,082 | ($96) | $2,494 | ($8,012) | $2,373 | $4,541 | ($7,299,234) | ($24,916) | ($22,157) | ($18,642) | ($17,851) | ($23,780) | ($7,399,198) |

Notes:
(A) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(B) Line 8 is reported on Schedule 4E and 5E
(C) Line 9a x Line 10
(D) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 8
PAGE 21 OF 21
FORM 42-8E
FILED: AUGUST 4, 2004

EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
FILED: SEPTEMBER 3, 2004

# ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

## JANUARY 2005 THROUGH DECEMBER 2005

## 42-1P THROUGH 42-7P

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040007-EI EXHIBIT NO. 13
COMPANY/ TECO
WITNESS: Howard T. Bryant (HTB-3)
DATE 11-08-04

EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
FILED: SEPTEMBER 3, 2004

# INDEX

## ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

## JANUARY 2005 THROUGH DECEMBER 2005

## 42-1P THROUGH 42-7P


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| 7 | Form 42-7P | 62 |




FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. _____ EXHIBIT NO. ____
COMPANY/
WITNESS: _____
DATE _____

Form 42 - 1P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
**January 2005 to December 2005**

| Line | Energy ($) | Demand ($) | Total ($) |
|---|---|---|---|
| 1. Total Jurisdictional Revenue Requirements for the projected period | | | |
| a. Projected O&M Activities (Form 42-2P, Lines 7, 8 & 9) | $8,080,178 | $515,353 | $8,595,531 |
| b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9) | 18,076,806 | 173,155 | 18,249,961 |
| c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b) | 26,156,984 | 688,508 | 26,845,492 |
| 2. True-up for Estimated Over/(Under) Recovery for the current period January 2004 December 2004 (Form 42-2E, Line 5 + 6 + 10) | 7,191,285 | 137,726 | 7,329,011 |
| 3. Final True-up for the period January 2003 to December 2003 (Form 42-1A, Line 3) | (256,262) | (4,089) | (260,351) |
| 4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2005 to December 2005 (Line 1 - Line 2- Line 3) | 19,221,961 | 554,870 | 19,776,832 |
| 5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier) | $19,235,801 | $555,269 | $19,791,071 |

Notes: Allocation to energy and demand in each period is in proportion to the respective period split of costs indicated on Lines 7 and 8 of Forms 42-5 and 42-7 of the actuals and estimates.



EXHIBIT NO.
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 1
PAGE 1 0F 1
FORM 42-1P
FILED: SEPTEMBER 3, 2004

Form 42-2P

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2005 to December 2005

O & M Activities
(in Dollars)

| Line | | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Description of O&M Activities | | | | | | | | | | | | | | | |
| | **Section** | | | | | | | | | | | | | | | |
| | **(1) AIR QUALITY** | | | | | | | | | | | | | | | |
| 1a. | Big Bend Unit 3 Flue Gas Desulfurization Integration | $186,930 | $186,930 | $186,930 | $186,930 | $186,930 | $186,930 | $186,930 | $186,930 | $186,930 | $186,930 | $186,930 | $183,770 | $2,240,000 | | $2,240,000 |
| 1b. | Big Bend Units 1 & 2 Flue Gas Conditioning | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| 1c. | $SO_2$ Emissions Allowances | (15,639) | (14,077) | (14,987) | (15,605) | (15,513) | (15,605) | (16,343) | (16,506) | (15,631) | (10,610) | (10,370) | (15,931) | (176,817) | | (176,817) |
| 1d. | Big Bend Units 1 & 2 FGD (Less Gypsum Revenues) | 349,997 | 361,367 | 362,087 | 355,047 | 357,977 | 355,357 | 352,087 | 350,687 | 377,087 | 395,917 | 394,107 | 371,337 | 4,383,050 | | 4,383,050 |
| 1e. | Big Bend PM Minimization and Monitoring | 88,000 | 88,000 | 88,000 | 88,000 | 88,000 | 88,000 | 88,000 | 88,000 | 88,000 | 88,000 | 88,000 | 82,000 | 1,050,000 | | 1,050,000 |
| 1f. | Big Bend $NO_x$ Emissions Reduction | 41,000 | 41,000 | 41,000 | 41,000 | 41,000 | 41,000 | 41,000 | 41,000 | 41,000 | 41,000 | 41,000 | 33,000 | 484,000 | | 484,000 |
| 1g. | Polk $NO_x$ Emissions Reduction | 2,800 | 2,800 | 2,800 | 2,800 | 2,800 | 2,800 | 2,800 | 2,800 | 2,800 | 2,800 | 2,800 | 2,800 | 33,600 | | 33,600 |
| 1h. | Bayside SCR Consumables | 9,583 | 9,583 | 9,583 | 9,583 | 9,583 | 9,583 | 9,583 | 9,583 | 9,583 | 9,583 | 9,583 | 9,583 | 115,000 | | 115,000 |
| 1i. | Big Bend Unit 4 SOFA | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 6,000 | 50,000 | | 50,000 |
| 1j. | Big Bend Unit 1 Pre-SCR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5,000 | 5,000 | 0 | 8,000 | 9,000 | 27,000 | | 27,000 |
| 1k. | Big Bend Unit 2 Pre-SCR | 2,000 | 2,000 | 1,000 | 2,000 | 2,000 | 1,000 | 2,000 | 2,000 | 1,000 | 2,000 | 3,000 | 3,000 | 23,000 | | 23,000 |
| 1l. | Big Bend Unit 3 Pre-SCR | 0 | 0 | 0 | 0 | 0 | 0 | 25,000 | 5,000 | 5,000 | 8,000 | 11,000 | 12,000 | 66,000 | | 66,000 |
| | **(2) LAND** | | | | | | | | | | | | | | | |
| | **(3) WATER** | | | | | | | | | | | | | | | |
| 3a. | NPDES Annual Surveillance Fees | 34,500 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 34,500 | 34,500 | |
| 3b. | Gannon Thermal Discharge Study | 10,000 | 25,000 | 25,000 | 40,000 | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 | 500,000 | 500,000 | |
| 2. | Total of O&M Activities | $713,171 | $706,603 | $705,413 | $713,755 | $726,777 | $723,065 | $745,057 | $728,494 | $754,769 | $777,620 | $788,050 | $746,559 | $8,829,333 | $534,500 | $8,294,833 |
| 3. | Recoverable Costs Allocated to Energy | 668,671 | 681,603 | 680,413 | 673,755 | 676,777 | 673,065 | 695,057 | 678,494 | 704,769 | 727,620 | 738,050 | 696,559 | 8,294,833 | | |
| 4. | Recoverable Costs Allocated to Demand | 44,500 | 25,000 | 25,000 | 40,000 | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 | 50,000 | 534,500 | | |
| 5. | Energy Jurisdictional Factor | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | | | |
| 6. | Demand Jurisdictional Factor | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | | | |
| 7. | Energy Jurisdictional Recoverable Costs (A) | 656,525 | 668,600 | 659,665 | 654,775 | 654,996 | 654,071 | 675,665 | 659,455 | 685,861 | 707,054 | 721,158 | 682,353 | 8,080,178 | | |
| 8. | Demand Jurisdictional Recoverable Costs (B) | 42,906 | 24,104 | 24,104 | 38,567 | 48,209 | 48,209 | 48,209 | 48,209 | 48,209 | 48,209 | 48,209 | 48,209 | 515,353 | | |
| 9. | Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8) | $699,431 | $692,704 | $683,769 | $693,342 | $703,205 | $702,280 | $723,874 | $707,664 | $734,070 | $755,263 | $769,367 | $730,562 | $8,595,531 | | |

Notes: (A) Line 3 x Line 5
(B) Line 4 x Line 6



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 2
PAGE 1 0F 1
FORM 42-2P
FILED: SEPTEMBER 3, 2004

Form 42-3P

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

**Capital Investment Projects-Recoverable Costs**
(in Dollars)

| Line | Description of Investment Projects (A) | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Section (1) AIR QUALITY** | | | | | | | | | | | | | | | |
| 1a. | Big Bend Unit 3 Flue Gas Desulfurization Integration | $77,918 | $77,731 | $77,545 | $77,358 | $77,172 | $76,985 | $76,798 | $76,612 | $76,425 | $76,239 | $76,053 | $75,866 | $922,702 | | $922,702 |
| 1b. | Big Bend Units 1 and 2 Flue Gas Conditioning | 47,328 | 47,170 | 47,011 | 46,853 | 46,694 | 46,536 | 46,378 | 46,219 | 46,060 | 45,902 | 45,743 | 45,585 | 557,479 | | 557,479 |
| 1c. | Big Bend Unit 4 Continuous Emissions Monitors | 8,034 | 8,015 | 7,997 | 7,977 | 7,958 | 7,940 | 7,920 | 7,902 | 7,883 | 7,864 | 7,845 | 7,826 | 95,161 | | 95,161 |
| 1d. | Big Bend Unit 1 Classifier Replacement | 14,311 | 14,269 | 14,227 | 14,185 | 14,141 | 14,099 | 14,057 | 14,014 | 13,971 | 13,929 | 13,886 | 13,843 | 168,932 | | 168,932 |
| 1e. | Big Bend Unit 2 Classifier Replacement | 10,486 | 10,456 | 10,426 | 10,396 | 10,366 | 10,336 | 10,305 | 10,275 | 10,245 | 10,214 | 10,184 | 10,154 | 123,843 | | 123,843 |
| 1f. | Big Bend Section 114 Mercury Testing Platform | 1,281 | 1,279 | 1,277 | 1,274 | 1,272 | 1,270 | 1,268 | 1,265 | 1,262 | 1,260 | 1,258 | 1,256 | 15,222 | | 15,222 |
| 1g. | Big Bend Units 1 & 2 FGD | 920,961 | 918,137 | 915,314 | 912,490 | 909,668 | 906,845 | 904,021 | 901,198 | 898,375 | 895,552 | 892,728 | 889,905 | 10,865,194 | | 10,865,194 |
| 1h. | Big Bend FGD Optimization and Utilization | 243,775 | 243,282 | 242,791 | 242,299 | 241,807 | 241,315 | 240,824 | 240,332 | 239,839 | 239,347 | 238,855 | 238,364 | 2,892,830 | | 2,892,830 |
| 1i. | Big Bend $NO_x$ Emissions Reduction | 56,419 | 56,711 | 57,002 | 57,390 | 57,753 | 67,262 | 76,555 | 76,372 | 76,189 | 76,006 | 75,823 | 75,640 | 809,122 | | 809,122 |
| 1j. | Big Bend PM Minimization and Monitoring | 90,379 | 102,113 | 101,874 | 101,635 | 101,397 | 101,159 | 100,920 | 100,681 | 100,444 | 100,205 | 99,966 | 99,728 | 1,200,501 | | 1,200,501 |
| 1k. | Polk $NO_x$ Emissions Reduction | 19,060 | 19,017 | 18,974 | 18,932 | 18,888 | 18,846 | 18,802 | 18,760 | 18,717 | 18,674 | 18,631 | 18,588 | 225,889 | | 225,889 |
| 1l. | Big Bend Unit 4 SOFA | 30,124 | 30,068 | 30,013 | 29,957 | 29,902 | 29,846 | 29,791 | 29,735 | 29,679 | 29,624 | 29,568 | 29,513 | 357,820 | | 357,820 |
| 1m. | Big Bend Unit 1 Pre-SCR | 4,245 | 4,390 | 4,633 | 5,021 | 5,483 | 5,967 | 6,453 | 6,962 | 8,903 | 13,778 | 18,121 | 19,989 | 103,945 | | 103,945 |
| 1n. | Big Bend Unit 2 Pre-SCR | 5,725 | 5,822 | 5,919 | 6,016 | 6,113 | 6,210 | 6,308 | 6,428 | 7,544 | 11,013 | 14,288 | 15,258 | 96,644 | | 96,644 |
| 1o. | Big Bend Unit 3 Pre-SCR | 4,900 | 4,997 | 5,240 | 5,652 | 6,113 | 6,962 | 8,224 | 9,194 | 10,794 | 15,137 | 20,425 | 24,113 | 121,751 | | 121,751 |
| 1p. | Big Bend Unit 4 SCR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| | **(2) LAND** | | | | | | | | | | | | | | | |
| 2a. | Big Bend Fuel Oil Tank #1 Upgrade | 5,143 | 5,133 | 5,121 | 5,110 | 5,100 | 5,089 | 5,078 | 5,067 | 5,056 | 5,046 | 5,035 | 5,023 | 61,001 | 61,001 | |
| 2b. | Big Bend Fuel Oil Tank #2 Upgrade | 8,459 | 8,440 | 8,423 | 8,405 | 8,387 | 8,369 | 8,351 | 8,333 | 8,315 | 8,298 | 8,279 | 8,262 | 100,321 | 100,321 | |
| 2c. | Phillips Upgrade Tank #1 for FDEP | 602 | 599 | 598 | 597 | 594 | 593 | 591 | 589 | 587 | 586 | 584 | 582 | 7,102 | 7,102 | |
| 2d. | Phillips Upgrade Tank #4 for FDEP | 946 | 943 | 940 | 938 | 935 | 931 | 929 | 926 | 923 | 921 | 918 | 915 | 11,165 | 11,165 | |
| 2. | Total Investment Projects - Recoverable Costs | $1,550,096 | $1,558,572 | $1,555,325 | $1,552,485 | $1,549,743 | $1,556,560 | $1,563,573 | $1,560,864 | $1,561,211 | $1,569,595 | $1,578,190 | $1,580,410 | $18,736,624 | $179,589 | $18,557,035 |
| 3. | Recoverable Costs Allocated to Energy | 1,534,946 | 1,543,457 | 1,540,243 | 1,537,435 | 1,534,727 | 1,541,578 | 1,548,624 | 1,545,949 | 1,546,330 | 1,554,744 | 1,563,374 | 1,565,628 | 18,557,035 | | |
| 4. | Recoverable Costs Allocated to Demand | 15,150 | 15,115 | 15,082 | 15,050 | 15,016 | 14,982 | 14,949 | 14,915 | 14,881 | 14,851 | 14,816 | 14,782 | 179,589 | | |
| 5. | Energy Jurisdictional Factor | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | | | |
| 6. | Demand Jurisdictional Factor | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | | | |
| 7. | Energy Jurisdictional Recoverable Costs (B) | 1,507,065 | 1,514,012 | 1,493,277 | 1,494,125 | 1,485,334 | 1,498,075 | 1,505,417 | 1,502,568 | 1,504,844 | 1,510,800 | 1,527,592 | 1,533,697 | 18,076,806 | | |
| 8. | Energy Jurisdictional Recoverable Costs (C) | 14,607 | 14,573 | 14,542 | 14,511 | 14,478 | 14,445 | 14,413 | 14,381 | 14,348 | 14,319 | 14,285 | 14,252 | 173,155 | | |
| 9. | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | $1,521,672 | $1,528,586 | $1,507,818 | $1,508,635 | $1,499,812 | $1,512,521 | $1,519,831 | $1,516,948 | $1,519,192 | $1,525,119 | $1,541,877 | $1,547,949 | $18,249,961 | | |

Notes: (A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9
(B) Line 3 x Line 5
(C) Line 4 x Line 6

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EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 3
PAGE 1 OF 1
FORM 42-3P
FILED: SEPTEMBER 3, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base | $8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | 8,239,658 | |
| 3. | Less: Accumulated Depreciation (A) | (2,181,321) | (2,200,547) | (2,219,773) | (2,238,999) | (2,258,225) | (2,277,451) | (2,296,677) | (2,315,903) | (2,335,129) | (2,354,355) | (2,373,581) | (2,392,807) | (2,412,033) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $6,058,337 | $6,039,111 | $6,019,885 | $6,000,659 | $5,981,433 | $5,962,207 | $5,942,981 | $5,923,755 | $5,904,529 | $5,885,303 | $5,866,077 | $5,846,851 | $5,827,625 | |
| 6. | Average Net Investment | | $6,048,724 | $6,029,498 | $6,010,272 | $5,991,046 | $5,971,820 | $5,952,594 | $5,933,368 | $5,914,142 | $5,894,916 | $5,875,690 | $5,856,464 | $5,837,238 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 44,477 | 44,336 | 44,195 | 44,053 | 43,912 | 43,770 | 43,629 | 43,488 | 43,346 | 43,205 | 43,064 | 42,922 | 524,397 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 14,215 | 14,169 | 14,124 | 14,079 | 14,034 | 13,989 | 13,943 | 13,898 | 13,853 | 13,808 | 13,763 | 13,718 | 167,593 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 19,226 | 230,712 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $77,918 | $77,731 | $77,545 | $77,358 | $77,172 | $76,985 | $76,798 | $76,612 | $76,425 | $76,239 | $76,053 | $75,866 | $922,702 |
| | a. Recoverable Costs Allocated to Energy | | 77,918 | 77,731 | 77,545 | 77,358 | 77,172 | 76,985 | 76,798 | 76,612 | 76,425 | 76,239 | 76,053 | 75,866 | 922,702 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 76,503 | 76,248 | 75,180 | 75,179 | 74,688 | 74,813 | 74,655 | 74,462 | 74,375 | 74,084 | 74,312 | 74,319 | 898,818 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $76,503 | $76,248 | $75,180 | $75,179 | $74,688 | $74,813 | $74,655 | $74,462 | $74,375 | $74,084 | $74,312 | $74,319 | $898,818 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 2.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 4
PAGE 1 OF 21
FORM 42-4P
FILED: SEPTEMBER 3, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 & 2 Flue Gas Conditioning
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | 5,017,734 | |
| 3. | Less: Accumulated Depreciation | (1,815,518) | (1,831,854) | (1,848,190) | (1,864,526) | (1,880,862) | (1,897,198) | (1,913,534) | (1,929,870) | (1,946,206) | (1,962,542) | (1,978,878) | (1,995,214) | (2,011,550) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $3,202,216 | $3,185,880 | $3,169,544 | $3,153,208 | $3,136,872 | $3,120,536 | $3,104,200 | $3,087,864 | $3,071,528 | $3,055,192 | $3,038,856 | $3,022,520 | $3,006,184 | |
| 6. | Average Net Investment | | $3,194,048 | $3,177,712 | $3,161,376 | $3,145,040 | $3,128,704 | $3,112,368 | $3,096,032 | $3,079,696 | $3,063,360 | $3,047,024 | $3,030,688 | $3,014,352 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 23,486 | 23,366 | 23,246 | 23,126 | 23,006 | 22,886 | 22,766 | 22,646 | 22,525 | 22,405 | 22,285 | 22,165 | 273,908 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 7,506 | 7,468 | 7,429 | 7,391 | 7,352 | 7,314 | 7,276 | 7,237 | 7,199 | 7,161 | 7,122 | 7,084 | 87,539 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 16,336 | 196,032 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $47,328 | $47,170 | $47,011 | $46,853 | $46,694 | $46,536 | $46,378 | $46,219 | $46,060 | $45,902 | $45,743 | $45,585 | $557,479 |
| | a. Recoverable Costs Allocated to Energy | | 47,328 | 47,170 | 47,011 | 46,853 | 46,694 | 46,536 | 46,378 | 46,219 | 46,060 | 45,902 | 45,743 | 45,585 | 557,479 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 46,468 | 46,270 | 45,578 | 45,533 | 45,191 | 45,223 | 45,084 | 44,922 | 44,824 | 44,605 | 44,696 | 44,655 | 543,049 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $46,468 | $46,270 | $45,578 | $45,533 | $45,191 | $45,223 | $45,084 | $44,922 | $44,824 | $44,605 | $44,696 | $44,655 | $543,049 |

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 and 312.42
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rates are 4.0% and 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 4
PAGE 2 OF 21
FORM 42-4P
FILED: SEPTEMBER 3, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | 866,211 | |
| 3. | Less: Accumulated Depreciation | (238,109) | (240,058) | (242,007) | (243,956) | (245,905) | (247,854) | (249,803) | (251,752) | (253,701) | (255,650) | (257,599) | (259,548) | (261,497) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $628,102 | $626,153 | $624,204 | $622,255 | $620,306 | $618,357 | $616,408 | $614,459 | $612,510 | $610,561 | $608,612 | $606,663 | $604,714 | |
| 6. | Average Net Investment | | $627,128 | $625,179 | $623,230 | $621,281 | $619,332 | $617,383 | $615,434 | $613,485 | $611,536 | $609,587 | $607,638 | $605,689 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 4,611 | 4,597 | 4,583 | 4,568 | 4,554 | 4,540 | 4,525 | 4,511 | 4,497 | 4,482 | 4,468 | 4,454 | 54,390 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,474 | 1,469 | 1,465 | 1,460 | 1,455 | 1,451 | 1,446 | 1,442 | 1,437 | 1,433 | 1,428 | 1,423 | 17,383 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 1,949 | 23,388 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $8,034 | $8,015 | $7,997 | $7,977 | $7,958 | $7,940 | $7,920 | $7,902 | $7,883 | $7,864 | $7,845 | $7,826 | $95,161 |
| | a. Recoverable Costs Allocated to Energy | | 8,034 | 8,015 | 7,997 | 7,977 | 7,958 | 7,940 | 7,920 | 7,902 | 7,883 | 7,864 | 7,845 | 7,826 | 95,161 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 7,888 | 7,862 | 7,753 | 7,752 | 7,702 | 7,716 | 7,699 | 7,680 | 7,672 | 7,642 | 7,665 | 7,666 | 92,697 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $7,888 | $7,862 | $7,753 | $7,752 | $7,702 | $7,716 | $7,699 | $7,680 | $7,672 | $7,642 | $7,665 | $7,666 | $92,697 |

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 2.7%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
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FORM 42-4P
FILED: SEPTEMBER 3, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank #1 Upgrade
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Investments | | | | | | | | | | | | | | |
| 1. | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | 497,578 | |
| 3. | Less: Accumulated Depreciation | (82,384) | (83,504) | (84,624) | (85,744) | (86,864) | (87,984) | (89,104) | (90,224) | (91,344) | (92,464) | (93,584) | (94,704) | (95,824) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $415,194 | $414,074 | $412,954 | $411,834 | $410,714 | $409,594 | $408,474 | $407,354 | $406,234 | $405,114 | $403,994 | $402,874 | $401,754 | |
| 6. | Average Net Investment | | $414,634 | $413,514 | $412,394 | $411,274 | $410,154 | $409,034 | $407,914 | $406,794 | $405,674 | $404,554 | $403,434 | $402,314 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 3,049 | 3,041 | 3,032 | 3,024 | 3,016 | 3,008 | 2,999 | 2,991 | 2,983 | 2,975 | 2,967 | 2,958 | 36,043 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 974 | 972 | 969 | 966 | 964 | 961 | 959 | 956 | 953 | 951 | 948 | 945 | 11,518 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 13,440 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $5,143 | $5,133 | $5,121 | $5,110 | $5,100 | $5,089 | $5,078 | $5,067 | $5,056 | $5,046 | $5,035 | $5,023 | 61,001 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 5,143 | 5,133 | 5,121 | 5,110 | 5,100 | 5,089 | 5,078 | 5,067 | 5,056 | 5,046 | 5,035 | 5,023 | 61,001 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 4,959 | 4,949 | 4,938 | 4,927 | 4,917 | 4,907 | 4,896 | 4,885 | 4,875 | 4,865 | 4,855 | 4,843 | $58,816 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $4,959 | $4,949 | $4,938 | $4,927 | $4,917 | $4,907 | $4,896 | $4,885 | $4,875 | $4,865 | $4,855 | $4,843 | 58,816 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 2.7%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
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FORM 42-4P
FILED: SEPTEMBER 3, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2005 to December 2005

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank #2 Upgrade
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | 818,401 | |
| 3. | Less: Accumulated Depreciation | (135,508) | (137,349) | (139,190) | (141,031) | (142,872) | (144,713) | (146,554) | (148,395) | (150,236) | (152,077) | (153,918) | (155,759) | (157,600) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $682,893 | $681,052 | $679,211 | $677,370 | $675,529 | $673,688 | $671,847 | $670,006 | $668,165 | $666,324 | $664,483 | $662,642 | $660,801 | |
| 6. | Average Net Investment | | $681,973 | $680,132 | $678,291 | $676,450 | $674,609 | $672,768 | $670,927 | $669,086 | $667,245 | $665,404 | $663,563 | $661,722 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 5,015 | 5,001 | 4,988 | 4,974 | 4,961 | 4,947 | 4,933 | 4,920 | 4,906 | 4,893 | 4,879 | 4,866 | 59,283 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,603 | 1,598 | 1,594 | 1,590 | 1,585 | 1,581 | 1,577 | 1,572 | 1,568 | 1,564 | 1,559 | 1,555 | 18,946 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 1,841 | 22,092 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $8,459 | $8,440 | $8,423 | $8,405 | $8,387 | $8,369 | $8,351 | $8,333 | $8,315 | $8,298 | $8,279 | $8,262 | $100,321 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 8,459 | 8,440 | 8,423 | 8,405 | 8,387 | 8,369 | 8,351 | 8,333 | 8,315 | 8,298 | 8,279 | 8,262 | 100,321 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 8,156 | 8,138 | 8,121 | 8,104 | 8,087 | 8,069 | 8,052 | 8,034 | 8,017 | 8,001 | 7,982 | 7,966 | 96,727 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $8,156 | $8,138 | $8,121 | $8,104 | $8,087 | $8,069 | $8,052 | $8,034 | $8,017 | $8,001 | $7,982 | $7,966 | $96,727 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 2.7%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO._____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-4P
FILED: SEPTEMBER 3, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2005 to December 2005

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank #1 for FDEP
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | 57,277 | |
| 3. | Less: Accumulated Depreciation | (13,872) | (14,053) | (14,234) | (14,415) | (14,596) | (14,777) | (14,958) | (15,139) | (15,320) | (15,501) | (15,682) | (15,863) | (16,044) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $43,405 | $43,224 | $43,043 | $42,862 | $42,681 | $42,500 | $42,319 | $42,138 | $41,957 | $41,776 | $41,595 | $41,414 | $41,233 | |
| 6. | Average Net Investment | | $43,315 | $43,134 | $42,953 | $42,772 | $42,591 | $42,410 | $42,229 | $42,048 | $41,867 | $41,686 | $41,505 | $41,324 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 319 | 317 | 316 | 315 | 313 | 312 | 311 | 309 | 308 | 307 | 305 | 304 | 3,736 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 102 | 101 | 101 | 101 | 100 | 100 | 99 | 99 | 98 | 98 | 98 | 97 | 1,194 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 181 | 2,172 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $602 | $599 | $598 | $597 | $594 | $593 | $591 | $589 | $587 | $586 | $584 | $582 | $7,102 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 602 | 599 | 598 | 597 | 594 | 593 | 591 | 589 | 587 | 586 | 584 | 582 | 7,102 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 580 | 578 | 577 | 576 | 573 | 572 | 570 | 568 | 566 | 565 | 563 | 561 | 6,848 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $580 | $578 | $577 | $576 | $573 | $572 | $570 | $568 | $566 | $565 | $563 | $561 | $6,848 |

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-4P
FILED: SEPTEMBER 3, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2005 to December 2005

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank #4 for FDEP
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | 90,472 | |
| 3. | Less: Accumulated Depreciation | (22,343) | (22,629) | (22,915) | (23,201) | (23,487) | (23,773) | (24,059) | (24,345) | (24,631) | (24,917) | (25,203) | (25,489) | (25,775) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $68,129 | $67,843 | $67,557 | $67,271 | $66,985 | $66,699 | $66,413 | $66,127 | $65,841 | $65,555 | $65,269 | $64,983 | $64,697 | |
| 6. | Average Net Investment | | $67,986 | $67,700 | $67,414 | $67,128 | $66,842 | $66,556 | $66,270 | $65,984 | $65,698 | $65,412 | $65,126 | $64,840 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 500 | 498 | 496 | 494 | 492 | 489 | 487 | 485 | 483 | 481 | 479 | 477 | 5,861 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 160 | 159 | 158 | 158 | 157 | 156 | 156 | 155 | 154 | 154 | 153 | 152 | 1,872 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 286 | 3,432 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $946 | $943 | $940 | $938 | $935 | $931 | $929 | $926 | $923 | $921 | $918 | $915 | $11,165 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 946 | 943 | 940 | 938 | 935 | 931 | 929 | 926 | 923 | 921 | 918 | 915 | 11,165 |
| | | | | | | | | | | | | | | | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 912 | 909 | 906 | 904 | 902 | 898 | 896 | 893 | 890 | 888 | 885 | 882 | 10,765 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $912 | $909 | $906 | $904 | $902 | $898 | $896 | $893 | $890 | $888 | $885 | $882 | $10,765 |

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
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FORM 42-4P
FILED: SEPTEMBER 3, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | 1,316,257 | |
| 3. | Less: Accumulated Depreciation | (291,320) | (295,708) | (300,096) | (304,484) | (308,872) | (313,260) | (317,648) | (322,036) | (326,424) | (330,812) | (335,200) | (339,588) | (343,976) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,024,937 | $1,020,549 | $1,016,161 | $1,011,773 | $1,007,385 | $1,002,997 | $998,609 | $994,221 | $989,833 | $985,445 | $981,057 | $976,669 | $972,281 | |
| 6. | Average Net Investment | | $1,022,743 | $1,018,355 | $1,013,967 | $1,009,579 | $1,005,191 | $1,000,803 | $996,415 | $992,027 | $987,639 | $983,251 | $978,863 | $974,475 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 7,520 | 7,488 | 7,456 | 7,424 | 7,391 | 7,359 | 7,327 | 7,295 | 7,262 | 7,230 | 7,198 | 7,165 | 88,115 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 2,403 | 2,393 | 2,383 | 2,373 | 2,362 | 2,352 | 2,342 | 2,331 | 2,321 | 2,311 | 2,300 | 2,290 | 28,161 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 4,388 | 52,656 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $14,311 | $14,269 | $14,227 | $14,185 | $14,141 | $14,099 | $14,057 | $14,014 | $13,971 | $13,929 | $13,886 | $13,843 | $168,932 |
| | a. Recoverable Costs Allocated to Energy | | 14,311 | 14,269 | 14,227 | 14,185 | 14,141 | 14,099 | 14,057 | 14,014 | 13,971 | 13,929 | 13,886 | 13,843 | 168,932 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 14,051 | 13,997 | 13,793 | 13,785 | 13,686 | 13,701 | 13,665 | 13,621 | 13,596 | 13,535 | 13,568 | 13,561 | 164,559 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $14,051 | $13,997 | $13,793 | $13,785 | $13,686 | $13,701 | $13,665 | $13,621 | $13,596 | $13,535 | $13,568 | $13,561 | $164,559 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 4.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



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DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
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FILED: SEPTEMBER 3, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | 984,794 | |
| 3. | Less: Accumulated Depreciation | (223,926) | (227,045) | (230,164) | (233,283) | (236,402) | (239,521) | (242,640) | (245,759) | (248,878) | (251,997) | (255,116) | (258,235) | (261,354) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $760,868 | $757,749 | $754,630 | $751,511 | $748,392 | $745,273 | $742,154 | $739,035 | $735,916 | $732,797 | $729,678 | $726,559 | $723,440 | |
| 6. | Average Net Investment | | $759,309 | $756,190 | $753,071 | $749,952 | $746,833 | $743,714 | $740,595 | $737,476 | $734,357 | $731,238 | $728,119 | $725,000 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 5,583 | 5,560 | 5,537 | 5,515 | 5,492 | 5,469 | 5,446 | 5,423 | 5,400 | 5,377 | 5,354 | 5,331 | 65,487 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,784 | 1,777 | 1,770 | 1,762 | 1,755 | 1,748 | 1,740 | 1,733 | 1,726 | 1,718 | 1,711 | 1,704 | 20,928 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 3,119 | 37,428 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $10,486 | $10,456 | $10,426 | $10,396 | $10,366 | $10,336 | $10,305 | $10,275 | $10,245 | $10,214 | $10,184 | $10,154 | $123,843 |
| | a. Recoverable Costs Allocated to Energy | | 10,486 | 10,456 | 10,426 | 10,396 | 10,366 | 10,336 | 10,305 | 10,275 | 10,245 | 10,214 | 10,184 | 10,154 | 123,843 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 10,296 | 10,257 | 10,108 | 10,103 | 10,032 | 10,044 | 10,017 | 9,987 | 9,970 | 9,925 | 9,951 | 9,947 | 120,637 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $10,296 | $10,257 | $10,108 | $10,103 | $10,032 | $10,044 | $10,017 | $9,987 | $9,970 | $9,925 | $9,951 | $9,947 | $120,637 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



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DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
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FILED: SEPTEMBER 3, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | 120,737 | |
| 3. | Less: Accumulated Depreciation | (13,399) | (13,640) | (13,881) | (14,122) | (14,363) | (14,604) | (14,845) | (15,086) | (15,327) | (15,568) | (15,809) | (16,050) | (16,291) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $107,338 | $107,097 | $106,856 | $106,615 | $106,374 | $106,133 | $105,892 | $105,651 | $105,410 | $105,169 | $104,928 | $104,687 | $104,446 | |
| 6. | Average Net Investment | | $107,218 | $106,977 | $106,736 | $106,495 | $106,254 | $106,013 | $105,772 | $105,531 | $105,290 | $105,049 | $104,808 | $104,567 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 788 | 787 | 785 | 783 | 781 | 780 | 778 | 776 | 774 | 772 | 771 | 769 | 9,344 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 252 | 251 | 251 | 250 | 250 | 249 | 249 | 248 | 247 | 247 | 246 | 246 | 2,986 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 2,892 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $1,281 | $1,279 | $1,277 | $1,274 | $1,272 | $1,270 | $1,268 | $1,265 | $1,262 | $1,260 | $1,258 | $1,256 | $15,222 |
| | a. Recoverable Costs Allocated to Energy | | 1,281 | 1,279 | 1,277 | 1,274 | 1,272 | 1,270 | 1,268 | 1,265 | 1,262 | 1,260 | 1,258 | 1,256 | 15,222 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 1,258 | 1,255 | 1,238 | 1,238 | 1,231 | 1,234 | 1,233 | 1,230 | 1,228 | 1,224 | 1,229 | 1,230 | 14,828 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $1,258 | $1,255 | $1,238 | $1,238 | $1,231 | $1,234 | $1,233 | $1,230 | $1,228 | $1,224 | $1,229 | $1,230 | $14,828 |

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO.
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-4P
FILED: SEPTEMBER 3, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | 83,129,721 | |
| 3. | Less: Accumulated Depreciation | (18,056,331) | (18,347,285) | (18,638,239) | (18,929,193) | (19,220,147) | (19,511,101) | (19,802,055) | (20,093,009) | (20,383,963) | (20,674,917) | (20,965,871) | (21,256,825) | (21,547,779) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $65,073,390 | $64,782,436 | $64,491,482 | $64,200,528 | $63,909,574 | $63,618,620 | $63,327,666 | $63,036,712 | $62,745,758 | $62,454,804 | $62,163,850 | $61,872,896 | $61,581,942 | |
| 6. | Average Net Investment | | $64,927,913 | $64,636,959 | $64,346,005 | $64,055,051 | $63,764,097 | $63,473,143 | $63,182,189 | $62,891,235 | $62,600,281 | $62,309,327 | $62,018,373 | $61,727,419 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 477,426 | 475,286 | 473,147 | 471,007 | 468,868 | 466,729 | 464,589 | 462,450 | 460,310 | 458,171 | 456,031 | 453,892 | 5,587,906 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 152,581 | 151,897 | 151,213 | 150,529 | 149,846 | 149,162 | 148,478 | 147,794 | 147,111 | 146,427 | 145,743 | 145,059 | 1,785,840 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 290,954 | 3,491,448 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $920,961 | $918,137 | $915,314 | $912,490 | $909,668 | $906,845 | $904,021 | $901,198 | $898,375 | $895,552 | $892,728 | $889,905 | $10,865,194 |
| | a. Recoverable Costs Allocated to Energy | | 920,961 | 918,137 | 915,314 | 912,490 | 909,668 | 906,845 | 904,021 | 901,198 | 898,375 | 895,552 | 892,728 | 889,905 | 10,865,194 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 904,232 | 900,622 | 887,404 | 886,785 | 880,392 | 881,254 | 878,799 | 875,909 | 874,273 | 870,240 | 872,295 | 871,755 | 10,583,960 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $904,232 | $900,622 | $887,404 | $886,785 | $880,392 | $881,254 | $878,799 | $875,909 | $874,273 | $870,240 | $872,295 | $871,755 | $10,583,960 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate 4.2%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
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FORM 42-4P
FILED: SEPTEMBER 3, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | 21,739,737 | |
| 3. | Less: Accumulated Depreciation | (1,815,865) | (1,866,561) | (1,917,257) | (1,967,953) | (2,018,649) | (2,069,345) | (2,120,041) | (2,170,737) | (2,221,433) | (2,272,129) | (2,322,825) | (2,373,521) | (2,424,217) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $19,923,872 | $19,873,176 | $19,822,480 | $19,771,784 | $19,721,088 | $19,670,392 | $19,619,696 | $19,569,000 | $19,518,304 | $19,467,608 | $19,416,912 | $19,366,216 | $19,315,520 | |
| 6. | Average Net Investment | | $19,898,524 | $19,847,828 | $19,797,132 | $19,746,436 | $19,695,740 | $19,645,044 | $19,594,348 | $19,543,652 | $19,492,956 | $19,442,260 | $19,391,564 | $19,340,868 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 146,317 | 145,944 | 145,572 | 145,199 | 144,826 | 144,453 | 144,081 | 143,708 | 143,335 | 142,962 | 142,589 | 142,217 | 1,731,203 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 46,762 | 46,642 | 46,523 | 46,404 | 46,285 | 46,166 | 46,047 | 45,928 | 45,808 | 45,689 | 45,570 | 45,451 | 553,275 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 50,696 | 608,352 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $243,775 | $243,282 | $242,791 | $242,299 | $241,807 | $241,315 | $240,824 | $240,332 | $239,839 | $239,347 | $238,855 | $238,364 | $2,892,830 |
| | a. Recoverable Costs Allocated to Energy | | 243,775 | 243,282 | 242,791 | 242,299 | 241,807 | 241,315 | 240,824 | 240,332 | 239,839 | 239,347 | 238,855 | 238,364 | 2,892,830 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 239,347 | 238,641 | 235,388 | 235,473 | 234,025 | 234,505 | 234,105 | 233,588 | 233,404 | 232,582 | 233,388 | 233,503 | 2,817,949 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $239,347 | $238,641 | $235,388 | $235,473 | $234,025 | $234,505 | $234,105 | $233,588 | $233,404 | $232,582 | $233,388 | $233,503 | $2,817,949 |

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.45 and 312.45
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rates are 2.1% and 2.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
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FORM 42-4P
FILED: SEPTEMBER 3, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend $NO_x$ Emissions Reduction
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $30,000 | $30,000 | $30,000 | $50,000 | $25,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $165,000 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | 0 | 0 | 0 | 0 | 0 | 5,964,555 | 5,964,555 | 5,964,555 | 5,964,555 | 5,964,555 | 5,964,555 | 5,964,555 | |
| 3. | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | (9,432) | (28,295) | (47,158) | (66,021) | (84,884) | (103,747) | (122,610) | |
| 4. | CWIP - Non-Interest Bearing | 5,799,555 | 5,829,555 | 5,859,555 | 5,889,555 | 5,939,555 | 5,964,555 | (0) | (0) | (0) | (0) | (0) | (0) | (0) | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $5,799,555 | $5,829,555 | $5,859,555 | $5,889,555 | $5,939,555 | $5,964,555 | $5,955,124 | $5,936,261 | $5,917,398 | $5,898,535 | $5,879,672 | $5,860,809 | $5,841,946 | |
| 6. | Average Net Investment | | $5,814,555 | $5,844,555 | $5,874,555 | $5,914,555 | $5,952,055 | $5,959,839 | $5,945,692 | $5,926,829 | $5,907,966 | $5,889,103 | $5,870,240 | $5,851,377 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 42,755 | 42,976 | 43,197 | 43,491 | 43,766 | 43,824 | 43,720 | 43,581 | 43,442 | 43,304 | 43,165 | 43,026 | 520,247 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 13,664 | 13,735 | 13,805 | 13,899 | 13,987 | 14,006 | 13,972 | 13,928 | 13,884 | 13,839 | 13,795 | 13,751 | 166,265 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 9,432 | 18,863 | 18,863 | 18,863 | 18,863 | 18,863 | 18,863 | 122,610 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $56,419 | $56,711 | $57,002 | $57,390 | $57,753 | $67,262 | $76,555 | $76,372 | $76,189 | $76,006 | $75,823 | $75,640 | $809,122 |
| | a. Recoverable Costs Allocated to Energy | | 56,419 | 56,711 | 57,002 | 57,390 | 57,753 | 67,262 | 76,555 | 76,372 | 76,189 | 76,006 | 75,823 | 75,640 | 809,122 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 55,394 | 55,629 | 55,264 | 55,773 | 55,894 | 65,364 | 74,419 | 74,229 | 74,145 | 73,858 | 74,088 | 74,097 | 788,154 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $55,394 | $55,629 | $55,264 | $55,773 | $55,894 | $65,364 | $74,419 | $74,229 | $74,145 | $73,858 | $74,088 | $74,097 | $788,154 |

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 and 312.42 and 312.43
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rates are 4.0%, 3.8% and 3.2%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO._____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
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FORM 42-4P
FILED: SEPTEMBER 3, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend PM Minimization and Monitoring
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $247,178 | 8,045,110 | 8,045,110 | 8,045,110 | 8,045,110 | 8,045,110 | 8,045,110 | 8,045,110 | 8,045,110 | 8,045,110 | 8,045,110 | 8,045,110 | 8,045,110 | |
| 3. | Less: Accumulated Depreciation | (29,114) | (41,774) | (66,348) | (90,922) | (115,496) | (140,070) | (164,644) | (189,218) | (213,792) | (238,366) | (262,940) | (287,514) | (312,089) | |
| 4. | CWIP - Non-Interest Bearing | 7,797,932 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $8,015,996 | $8,003,336 | $7,978,762 | $7,954,188 | $7,929,614 | $7,905,040 | $7,880,466 | $7,855,892 | $7,831,318 | $7,806,744 | $7,782,170 | $7,757,596 | $7,733,021 | |
| 6. | Average Net Investment | | $8,009,666 | $7,991,049 | $7,966,475 | $7,941,901 | $7,917,327 | $7,892,753 | $7,868,179 | $7,843,605 | $7,819,031 | $7,794,457 | $7,769,883 | $7,745,308 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 58,896 | 58,760 | 58,579 | 58,398 | 58,217 | 58,037 | 57,856 | 57,675 | 57,495 | 57,314 | 57,133 | 56,953 | 695,313 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 18,823 | 18,779 | 18,721 | 18,663 | 18,606 | 18,548 | 18,490 | 18,432 | 18,375 | 18,317 | 18,259 | 18,201 | 222,214 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 12,660 | 24,574 | 24,574 | 24,574 | 24,574 | 24,574 | 24,574 | 24,574 | 24,574 | 24,574 | 24,574 | 24,574 | 282,974 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $90,379 | $102,113 | $101,874 | $101,635 | $101,397 | $101,159 | $100,920 | $100,681 | $100,444 | $100,205 | $99,966 | $99,728 | $1,200,501 |
| | a. Recoverable Costs Allocated to Energy | | 90,379 | 102,113 | 101,874 | 101,635 | 101,397 | 101,159 | 100,920 | 100,681 | 100,444 | 100,205 | 99,966 | 99,728 | 1,200,501 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 88,737 | 100,165 | 98,768 | 98,772 | 98,134 | 98,304 | 98,104 | 97,856 | 97,749 | 97,373 | 97,678 | 97,694 | 1,169,334 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $88,737 | $100,165 | $98,768 | $98,772 | $98,134 | $98,304 | $98,104 | $97,856 | $97,749 | $97,373 | $97,678 | $97,694 | $1,169,334 |

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41, 312.42, 312.43, 315.40, 315.43 and 315.44
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rates are 4.0%, 3.8%, 3.2%, 3.4%, 3.1%, and 2.7%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
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FILED: SEPTEMBER 3, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Polk $NO_x$ Emissions Reduction
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | 1,561,473 | |
| 3. | Less: Accumulated Depreciation | (50,881) | (55,305) | (59,729) | (64,153) | (68,577) | (73,001) | (77,425) | (81,849) | (86,273) | (90,697) | (95,121) | (99,545) | (103,969) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $1,510,592 | $1,506,168 | $1,501,744 | $1,497,320 | $1,492,896 | $1,488,472 | $1,484,048 | $1,479,624 | $1,475,200 | $1,470,776 | $1,466,352 | $1,461,928 | $1,457,504 | |
| 6. | Average Net Investment | | $1,508,380 | $1,503,956 | $1,499,532 | $1,495,108 | $1,490,684 | $1,486,260 | $1,481,836 | $1,477,412 | $1,472,988 | $1,468,564 | $1,464,140 | $1,459,716 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 11,091 | 11,059 | 11,026 | 10,994 | 10,961 | 10,929 | 10,896 | 10,864 | 10,831 | 10,799 | 10,766 | 10,734 | 130,950 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 3,545 | 3,534 | 3,524 | 3,514 | 3,503 | 3,493 | 3,482 | 3,472 | 3,462 | 3,451 | 3,441 | 3,430 | 41,851 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 4,424 | 53,088 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $19,060 | $19,017 | $18,974 | $18,932 | $18,888 | $18,846 | $18,802 | $18,760 | $18,717 | $18,674 | $18,631 | $18,588 | $225,889 |
| | a. Recoverable Costs Allocated to Energy | | 19,060 | 19,017 | 18,974 | 18,932 | 18,888 | 18,846 | 18,802 | 18,760 | 18,717 | 18,674 | 18,631 | 18,588 | 225,889 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 18,714 | 18,654 | 18,395 | 18,399 | 18,280 | 18,314 | 18,277 | 18,234 | 18,215 | 18,146 | 18,205 | 18,209 | 220,042 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $18,714 | $18,654 | $18,395 | $18,399 | $18,280 | $18,314 | $18,277 | $18,234 | $18,215 | $18,146 | $18,205 | $18,209 | $220,042 |

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 4
PAGE 15 OF 21
FORM 42-4P
FILED: SEPTEMBER 3, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $2,543,334 | 2,543,334 | 2,543,334 | 2,543,334 | 2,543,334 | 2,543,334 | 2,543,334 | 2,543,334 | 2,543,334 | 2,543,334 | 2,543,334 | 2,543,334 | 2,543,334 | |
| 3. | Less: Accumulated Depreciation | (25,754) | (31,477) | (37,200) | (42,923) | (48,646) | (54,369) | (60,092) | (65,815) | (71,538) | (77,261) | (82,984) | (88,707) | (94,430) | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $2,517,580 | $2,511,857 | $2,506,134 | $2,500,411 | $2,494,688 | $2,488,965 | $2,483,242 | $2,477,519 | $2,471,796 | $2,466,073 | $2,460,350 | $2,454,627 | $2,448,904 | |
| 6. | Average Net Investment | | $2,514,719 | $2,508,996 | $2,503,273 | $2,497,550 | $2,491,827 | $2,486,104 | $2,480,381 | $2,474,658 | $2,468,935 | $2,463,212 | $2,457,489 | $2,451,766 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 18,491 | 18,449 | 18,407 | 18,365 | 18,323 | 18,281 | 18,239 | 18,197 | 18,154 | 18,112 | 18,070 | 18,028 | 219,116 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 5,910 | 5,896 | 5,883 | 5,869 | 5,856 | 5,842 | 5,829 | 5,815 | 5,802 | 5,789 | 5,775 | 5,762 | 70,028 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 5,723 | 5,723 | 5,723 | 5,723 | 5,723 | 5,723 | 5,723 | 5,723 | 5,723 | 5,723 | 5,723 | 5,723 | 68,676 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 + 8) | | $30,124 | $30,068 | $30,013 | $29,957 | $29,902 | $29,846 | $29,791 | $29,735 | $29,679 | $29,624 | $29,568 | $29,513 | $357,820 |
| | a. Recoverable Costs Allocated to Energy | | 30,124 | 30,068 | 30,013 | 29,957 | 29,902 | 29,846 | 29,791 | 29,735 | 29,679 | 29,624 | 29,568 | 29,513 | 357,820 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (D) | | 29,577 | 29,494 | 29,098 | 29,113 | 28,940 | 29,004 | 28,960 | 28,901 | 28,883 | 28,787 | 28,891 | 28,911 | 348,559 |
| 13. | Demand Jurisdictional Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $29,577 | $29,494 | $29,098 | $29,113 | $28,940 | $29,004 | $28,960 | $28,901 | $28,883 | $28,787 | $28,891 | $28,911 | $348,559 |

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 2.7%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 4
PAGE 16 OF 21
FORM 42-4P
FILED: SEPTEMBER 3, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
January 2005 to December 2005

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $15,000 | $15,000 | $35,000 | $45,000 | $50,000 | $50,000 | $50,000 | $55,000 | $345,000 | $660,000 | $235,000 | $150,000 | $1,705,000 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3. | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4. | CWIP - Non-Interest Bearing | 430,000 | 445,000 | 460,000 | 495,000 | 540,000 | 590,000 | 640,000 | 690,000 | 745,000 | 1,090,000 | 1,750,000 | 1,985,000 | 2,135,000 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $430,000 | $445,000 | $460,000 | $495,000 | $540,000 | $590,000 | $640,000 | $690,000 | $745,000 | $1,090,000 | $1,750,000 | $1,985,000 | $2,135,000 | |
| 6. | Average Net Investment | | $437,500 | $452,500 | $477,500 | $517,500 | $565,000 | $615,000 | $665,000 | $717,500 | $917,500 | $1,420,000 | $1,867,500 | $2,060,000 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 3,217 | 3,327 | 3,511 | 3,805 | 4,155 | 4,522 | 4,890 | 5,276 | 6,747 | 10,441 | 13,732 | 15,148 | 78,771 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,028 | 1,063 | 1,122 | 1,216 | 1,328 | 1,445 | 1,563 | 1,686 | 2,156 | 3,337 | 4,389 | 4,841 | 25,174 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $4,245 | $4,390 | $4,633 | $5,021 | $5,483 | $5,967 | $6,453 | $6,962 | $8,903 | $13,778 | $18,121 | $19,989 | $103,945 |
| | a. Recoverable Costs Allocated to Energy | | 4,245 | 4,390 | 4,633 | 5,021 | 5,483 | 5,967 | 6,453 | 6,962 | 8,903 | 13,778 | 18,121 | 19,989 | 103,945 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 4,168 | 4,306 | 4,492 | 4,880 | 5,307 | 5,799 | 6,273 | 6,767 | 8,664 | 13,389 | 17,706 | 19,581 | 101,332 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $4,168 | $4,306 | $4,492 | $4,880 | $5,307 | $5,799 | $6,273 | $6,767 | $8,664 | $13,389 | $17,706 | $19,581 | $101,332 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 4.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 4
PAGE 17 OF 21
FORM 42-4P
FILED: SEPTEMBER 3, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
January 2005 to December 2005

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $10,000 | $15,000 | $215,000 | $500,000 | $175,000 | $25,000 | $1,000,000 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3. | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4. | CWIP - Non-Interest Bearing | 585,000 | 595,000 | 605,000 | 615,000 | 625,000 | 635,000 | 645,000 | 655,000 | 670,000 | 885,000 | 1,385,000 | 1,560,000 | 1,585,000 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $585,000 | $595,000 | $605,000 | $615,000 | $625,000 | $635,000 | $645,000 | $655,000 | $670,000 | $885,000 | $1,385,000 | $1,560,000 | $1,585,000 | |
| 6. | Average Net Investment | | $590,000 | $600,000 | $610,000 | $620,000 | $630,000 | $640,000 | $650,000 | $662,500 | $777,500 | $1,135,000 | $1,472,500 | $1,572,500 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 4,338 | 4,412 | 4,485 | 4,559 | 4,632 | 4,706 | 4,780 | 4,871 | 5,717 | 8,346 | 10,828 | 11,563 | 73,237 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,387 | 1,410 | 1,434 | 1,457 | 1,481 | 1,504 | 1,528 | 1,557 | 1,827 | 2,667 | 3,460 | 3,695 | 23,407 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $5,725 | $5,822 | $5,919 | $6,016 | $6,113 | $6,210 | $6,308 | $6,428 | $7,544 | $11,013 | $14,288 | $15,258 | $96,644 |
| | a. Recoverable Costs Allocated to Energy | | 5,725 | 5,822 | 5,919 | 6,016 | 6,113 | 6,210 | 6,308 | 6,428 | 7,544 | 11,013 | 14,288 | 15,258 | 96,644 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 5,621 | 5,711 | 5,739 | 5,847 | 5,916 | 6,035 | 6,132 | 6,248 | 7,342 | 10,702 | 13,961 | 14,947 | 94,201 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $5,621 | $5,711 | $5,739 | $5,847 | $5,916 | $6,035 | $6,132 | $6,248 | $7,342 | $10,702 | $13,961 | $14,947 | $94,201 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 4.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
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PAGE 18 OF 21
FORM 42-4P
FILED: SEPTEMBER 3, 2004

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
January 2005 to December 2005

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $10,000 | $10,000 | $40,000 | $45,000 | $50,000 | $125,000 | $135,000 | $65,000 | $265,000 | $630,000 | $460,000 | $300,000 | $2,135,000 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3. | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4. | CWIP - Non-Interest Bearing | 500,000 | 510,000 | 520,000 | 560,000 | 605,000 | 655,000 | 780,000 | 915,000 | 980,000 | 1,245,000 | 1,875,000 | 2,335,000 | 2,635,000 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $500,000 | $510,000 | $520,000 | $560,000 | $605,000 | $655,000 | $780,000 | $915,000 | $980,000 | $1,245,000 | $1,875,000 | $2,335,000 | $2,635,000 | |
| 6. | Average Net Investment | | $505,000 | $515,000 | $540,000 | $582,500 | $630,000 | $717,500 | $847,500 | $947,500 | $1,112,500 | $1,560,000 | $2,105,000 | $2,485,000 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 3,713 | 3,787 | 3,971 | 4,283 | 4,632 | 5,276 | 6,232 | 6,967 | 8,180 | 11,471 | 15,478 | 18,273 | 92,263 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 1,187 | 1,210 | 1,269 | 1,369 | 1,481 | 1,686 | 1,992 | 2,227 | 2,614 | 3,666 | 4,947 | 5,840 | 29,488 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $4,900 | $4,997 | $5,240 | $5,652 | $6,113 | $6,962 | $8,224 | $9,194 | $10,794 | $15,137 | $20,425 | $24,113 | $121,751 |
| | a. Recoverable Costs Allocated to Energy | | 4,900 | 4,997 | 5,240 | 5,652 | 6,113 | 6,962 | 8,224 | 9,194 | 10,794 | 15,137 | 20,425 | 24,113 | 121,751 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 4,811 | 4,902 | 5,080 | 5,493 | 5,916 | 6,766 | 7,995 | 8,936 | 10,504 | 14,709 | 19,958 | 23,621 | 118,691 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | $4,811 | $4,902 | $5,080 | $5,493 | $5,916 | $6,766 | $7,995 | $8,936 | $10,504 | $14,709 | $19,958 | $23,621 | $118,691 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.8%
(D) Line 9a x Line 10
(E) Line 9b x Line 11



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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Actual Period Amount
January 2005 to December 2005

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Expenditures/Additions | | $500,000 | $650,000 | $750,000 | $750,000 | $775,000 | $775,000 | $825,000 | $900,000 | $1,000,000 | $950,000 | $825,000 | $800,000 | $9,500,000 |
| | b. Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Plant-in-Service/Depreciation Base (A) | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3. | Less: Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 4. | CWIP - Non-Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Net Investment (Lines 2 + 3 + 4) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 6. | Average Net Investment | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 7. | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (B) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Debt Component (Line 6 x 2.82% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8. | Investment Expenses | | | | | | | | | | | | | | |
| | a. Depreciation (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Amortization | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d. Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e. Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9. | Total System Recoverable Expenses (Lines 7 +8) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | a. Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Retail Energy-Related Recoverable Costs (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13. | Retail Demand-Related Recoverable Costs (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(C) Applicable depreciation rate is 3.2%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.



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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 to December 2005**

For Project: $SO_2$ Emissions Allowances
(in Dollars)

| Line | Description | Beginning of Period Amount | Projected Jan-05 | Projected Feb-05 | Projected Mar-05 | Projected Apr-05 | Projected May-05 | Projected Jun-05 | Projected Jul-05 | Projected Aug-05 | Projected Sep-05 | Projected Oct-05 | Projected Nov-05 | Projected Dec-05 | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | Investments | | | | | | | | | | | | | | |
| | a. Purchases/Transfers | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | b. Sales/Transfers | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. Auction Proceeds/Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2. | Working Capital Balance | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | a. FERC 158.1 Allowance Inventory | $0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b. FERC 158.2 Allowances Withheld | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c. FERC 182.3 Other Regl. Assets - Losses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d. FERC 254 Regulatory Liabilities - Gains | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 3. | Total Working Capital Balance | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 4. | Average Net Working Capital Balance | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5. | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a. Equity Component Grossed Up For Taxes (A) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Debt Component (Line 4 x 2.82% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6. | Total Return Component (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7. | Expenses: | | | | | | | | | | | | | | |
| | a. Gains | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b. Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c. $SO_2$ Allowance Expense | | (15,639) | (14,077) | (14,987) | (15,605) | (15,513) | (15,605) | (16,343) | (16,506) | (15,631) | (10,610) | (10,370) | (15,931) | (176,817) |
| 8. | Net Expenses (E) | | (15,639) | (14,077) | (14,987) | (15,605) | (15,513) | (15,605) | (16,343) | (16,506) | (15,631) | (10,610) | (10,370) | (15,931) | (176,817) |
| 9. | Total System Recoverable Expenses (Lines 6 + 7) | | ($15,639) | ($14,077) | ($14,987) | ($15,605) | ($15,513) | ($15,605) | ($16,343) | ($16,506) | ($15,631) | ($10,610) | ($10,370) | ($15,931) | ($176,817) |
| | a. Recoverable Costs Allocated to Energy | | (15,639) | (14,077) | (14,987) | (15,605) | (15,513) | (15,605) | (16,343) | (16,506) | (15,631) | (10,610) | (10,370) | (15,931) | (176,817) |
| | b. Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10. | Energy Jurisdictional Factor | | 0.9818356 | 0.9809229 | 0.9695073 | 0.9718295 | 0.9678167 | 0.9717804 | 0.9720999 | 0.9719386 | 0.9731714 | 0.9717357 | 0.9771121 | 0.9796050 | |
| 11. | Demand Jurisdictional Factor | | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | 0.9641722 | |
| 12. | Energy Jurisdictional Recoverable Costs (B) | | (15,355) | (13,808) | (14,530) | (15,165) | (15,014) | (15,165) | (15,887) | (16,043) | (15,212) | (10,310) | (10,133) | (15,606) | (172,228) |
| 13. | Demand Jurisdictional Recoverable Costs (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14. | Total Juris. Recoverable Costs (Lines 12 + 13) | | ($15,355) | ($13,808) | ($14,530) | ($15,165) | ($15,014) | ($15,165) | ($15,887) | ($16,043) | ($15,212) | ($10,310) | ($10,133) | ($15,606) | ($172,228) |

Notes: (A) Lines 4 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002)
(B) Line 9a x Line 10
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E



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**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Unit 3 Flue Gas Desulfurization Integration

**Project Description:**

This project involved the integration of Big Bend Unit 3 flue gases into the Big Bend Unit 4 Flue Gas Desulfurization ("FGD") system. The integration was accomplished by installing interconnecting ductwork between Unit 3 precipitator outlet ducts and the Unit 4 FGD inlet duct. The Unit 4 FGD outlet duct was interconnected with the Unit 3 chimney via new ductwork and a new stack breaching. New ductwork, linings, isolation dampers, support steel, and stack annulus pressurization fans were procured and installed. Modifications to the materials handling systems and controls were also necessary.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $949,565 compared to the original projection of $949,565 representing no variance.

The actual/estimated O&M expense for the period January 2004 through December 2004 is $1,965,676 compared to the original projection of $2,206,000 representing a variance of –10.9%. This variance resulted primarily from the decrease in the cost of consumables, principally potable water and chemicals, from the original projection. Additionally, a change was made in the outage schedule which did not permit for originally planned maintenance to occur in 2004.

Project Progress Summary: The project is complete and in service.

Project Projections: Estimated depreciation plus return for the period January 2005 through December 2005 is expected to be $922,702.

Estimated O&M costs for the period January 2005 through December 2005 are projected to be $2,240,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Units 1 & 2 Flue Gas Conditioning

**Project Description:**

The existing electrostatic precipitators were not designed for the range of fuels needed for compliance with the Clean Air Act Amendments ("CAAA"). Flue gas conditioning was required to assure operation of the generating units in accordance with applicable permits and regulations. This equipment is still required to ensure compliance with the CAAA in the event the FGD system on Units 1 & 2 is not operating.

The project involved the addition of molten sulfur unloading, storage and conveying to sulfur burners and catalytic converters where $SO_2$ is converted to $SO_3$. The control and injection system then injects this into the ductwork ahead of the electrostatic precipitators.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $580,305 compared to the original projection of $580,305 representing no variance.

The actual/estimated O&M expense for this project for the period January 2004 through December 2004 is $0 and did not vary from the original projection.

Project Progress Summary: The project is complete and in service.

Project Projections: Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $557,479.

Estimated O&M costs for the period January 2005 through December 2005 are projected to be $0.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Unit 4 Continuous Emissions Monitors

**Project Description:**

Continuous emissions monitors (CEMs) were installed on the flue gas inlet and outlet of Big Bend Unit 4 to monitor compliance with the CAAA requirements. The monitors are capable of measuring, recording and electronically reporting $SO_2$, $NO_x$ and volumetric gas flow out of the stack. The project consisted of monitors, a CEM building, the CEMs control and power cables to supply a complete system.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMs and specific requirements for the monitoring of pollutants, opacity and volumetric flow. These regulations are very comprehensive and specific as to the requirements for CEMs, and in essence, they define the components needed and their configuration.

**Project Accomplishment:**

| | |
|---|---|
| Project Fiscal Expenditures: | The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $97,884 and did not vary from the original projection. |
| Project Progress Summary: | The project is complete and in service. |
| Project Projections: | Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $95,161. |

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Unit 1 Classifier Replacement

**Project Description:**

The boiler modifications at Big Bend Unit 1 are part of Tampa Electric's $NO_X$ compliance strategy for Phase II of the CAAA. The classifier replacements will optimize coal fineness by providing a more uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, will enable a uniform, staged combustion. As a result, firing systems will operate at lower $NO_X$ levels.

**Project Accomplishments:**

| | |
|---|---|
| Project Fiscal Expenditures: | The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $175,064 compared to the original projection of $175,064 representing no variance. |
| Progress Summary: | The project is complete and was placed in service December 1998. |
| Project Projections: | Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $168,932. |

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Unit 2 Classifier Replacement

**Project Description:**

The boiler modifications at Big Bend Unit 2 are part of Tampa Electric's $NO_X$ compliance strategy for Phase II of the CAAA. The classifier replacements will optimize coal fineness by providing a more uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, will enable a uniform, staged combustion. As a result, firing systems will operate at lower $NO_X$ levels.

**Project Accomplishments:**

| | |
|---|---|
| Project Fiscal Expenditures: | The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $128,202 compared to the original projection of $128,202 representing no variance. |
| Progress Summary: | The project is complete and was placed in service May 1998. |
| Project Projections: | Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $123,843. |

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Units 1 & 2 FGD

**Project Description:**

The Big Bend Units 1 & 2 FGD system consists of equipment capable of removing $SO_2$ from the flue gas generated by the combustion of coal. The FGD was installed in order to comply with Phase II of the CAAA. Compliance with Phase II is required by January 1, 2000. The CAAA impose $SO_2$ emission limits on existing steam electric units with an output capacity of greater than 25 megawatts and all new utility units. Tampa Electric conducted an exhaustive analysis of options to comply with Phase II of the CAAA that culminated in the selection of the FGD project to serve Big Bend Units 1 & 2.

In Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999, the Commission found that the FGD project was the most cost-effective alternative for compliance with the $SO_2$ requirements of Phase II of the CAAA.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $11,271,732 compared to the original projection of $11,271,732 representing no variance.

The actual/estimated O&M expense for the period January 2004 through December 2004 is $4,774,156 as compared to the original estimate of $4,288,700 resulting in a variance of 11.3%. This variance resulted primarily from an outage schedule change that allowed for a major inspection and subsequent maintenance on towers, inlet ducts, oxidation air headers, absorber pumps and structural steel replacement. This activity was not originally planned for 2004.

Project Progress Summary: The project was placed in service in December 1999.

Project Projections: Estimated depreciation plus return for the period January 2005 through December 2005 is expected to be $10,865,194.

Estimated O&M costs for the period January 2005 through December 2005 are projected to be $4,383,050.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Section 114 Mercury Testing Platform

**Project Description:**

The Mercury Emissions Information Collection Effort is mandated by the EPA. The EPA asserts that Section 114 of the CAAA grants to the EPA the authority to request the collection of information necessary for it to study whether it is appropriate and necessary to develop performance or emission standards for electric utility steam generating units.

In a letter dated November 25, 1998, Tampa Electric was notified by the EPA that, pursuant to Section 114 of the CAAA, the company was required to periodically sample and analyze coal shipments for mercury and chlorine content during the period January 1, 1999 through December 31, 1999.

In addition to coal sampling, stack testing and analyses are also required. Tampa Electric received a second letter from EPA, dated March 11, 1999, requiring Tampa Electric to perform speciated mercury testing of the inlet and outlet of the last emission control device installed for Big Bend Units 1, 2 or 3, and Polk Unit 1 as part of the mercury data collection. Part of the cost incurred to perform the stack testing is due to the need to construct special test facilities at the Big Bend stack testing location to meet EPA's testing requirements.

**Project Accomplishments:**

| | |
|---|---|
| Project Fiscal Expenditures: | The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $15,559 compared to the original projection of $15,559 representing no variance. |
| Project Progress Summary: | The project was placed in service in December 1999 and was completed in May 2000. |
| Project Projections: | Estimated depreciation plus return for the period January 2005 through December 2005 is expected to be $15,222. |

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend FGD Optimization and Utilization

**Project Description:**

In order to meet the requirements of the FDEP Consent Final Judgement and the EPA Consent Decree, Tampa Electric was required to optimize the $SO_2$ removal efficiency and operations of the Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric performed activities in three key areas to improve the performance and reliability of the Big Bend Units 1, 2 and 3 FGD systems. The majority of the improvements were required to be performed on the Unit 3 tower module and included tower piping, nozzle and internal improvements, duct work improvements, electrical system reliability improvements, tower control improvements, dibasic acid system improvements, booster fan reliability improvements, absorber system improvements, quencher system improvements, and tower demister improvements. Big Bend Units 1 and 2 FGD system improvements included additional preventative maintenance, oxidation air control improvements, and tower water, air reagent and start-up piping upgrades. In order to ensure reliability of the FGD systems, improvements to the common limestone supply, gypsum dewatering stack reliability and wastewater treatment plant were also being performed.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $2,963,665 as compared to the original projection of $2,912,246 resulting in a variance of 1.8%. This variance is due to a Commission field audit request to lower the plant-in-service amount just prior to the submission of the 2004 projection. However, upon further review at a later date by the company and the Commission field audit personnel, the plant-in-service amount was restored to its original amount thereby creating the current variance.

Project Progress Summary: The project was placed in service in January 2002.

Project Projections: Estimated depreciation plus return for the period January 2005 through December 2005 is expected to be $2,892,830.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend PM Minimization and Monitoring

**Project Description:**

In order to meet the requirements of the FDEP Consent Final Judgement and the EPA Consent Decree, Tampa Electric is required to develop a Best Operational Practices ("BOP") study to minimize emissions from each electrostatic precipitator ("ESP") at Big Bend, to perform a best available control technology ("BACT") analysis for the upgrade of each existing ESP, and to install and operate particulate matter continuous emission monitors. and operations of the Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric has identified improvements that are necessary to optimize ESP performance such as modifications to the turning vanes and precipitator distribution plates, and upgrades to the controls and software system of the precipitators. Tampa Electric has incurred costs associated with the recommendations of the BOP study and the BACT analysis in 2001 and will continue to experience O&M and capital expenditures during 2002 and beyond.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $848,091 as compared to the original projection of $915,233 resulting in a variance of -7.3%. This variance was primarily due to a change in maintenance outages from spring to fall of 2004.

The actual/estimated O&M expense the period January 2004 through December 2004 is $1,000,484 as compared to the original projection of $980,000 resulting in an insignificant variance of 2.1%.

Project Progress Summary: The project is being placed in service January 2005.

Project Projections: Estimated depreciation plus return for the period January 2005 through December 2005 is expected to be $1,200,501.

Estimated O&M costs for the period January 2005 through December 2005 are projected to be $1,050,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend $NO_x$ Emissions Reduction

**Project Description:**

In order to meet the requirements of the FDEP Consent Final Judgement and the EPA Consent Decree, Tampa Electric is required to spend up to $3 million with the goal to reduce $NO_x$ emissions at Big Bend Station. The Consent Decree requires that by December 31, 2002, the company must achieve at least a 30 percent reduction beyond 1998 levels for Big Bend Units 1 and 2 and at least a 15 percent reduction in $NO_x$ emissions from Big Bend Unit 3. Tampa Electric has identified projects which are the first steps to decrease $NO_x$ emissions in these units such as burner and windbox modifications and the installation of a neural network system on each of the Big Bend units.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $620,346 as compared to the original projection of $605,009 resulting in an insignificant variance of 2.5%.

The actual/estimated O&M expense the period January 2004 through December 2004 is $500,034 as compared to the original projection of $545,000 resulting in a variance of -8.3%. This variance is due to less testing and maintenance related to coal fineness.

Project Progress Summary: The project is being placed in service June 2005.

Project Projections: Estimated depreciation plus return for the period January 2005 through December 2005 is expected to be $809,122.

Estimated O&M costs for the period January 2005 through December 2005 are projected to be $484,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Fuel Oil Tank No. 1 Upgrade

**Project Description:**

The Big Bend Fuel Oil Tank No. 1 Upgrade is a 500,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, applying a coating to the internal floor and 30 inches up the tank wall, installing an "El Segundo" bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

**Project Accomplishments:**

| | |
|---|---|
| Project Fiscal Expenditures: | The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $62,567 compared to the original projection of $62,567 representing no variance. |
| Project Progress Summary: | The project is complete and was placed in service October 1998. |
| Project Projections: | Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $61,001. |

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Fuel Oil Tank No. 2 Upgrade

**Project Description:**

The Big Bend Fuel Oil Tank No. 2 Upgrade is a 4,200,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, applying a coating to the internal floor and 30 inches up the tank wall, installing an "El Segundo" bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

**Project Accomplishments:**

| | |
|---|---|
| Project Fiscal Expenditures: | The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $102,893 compared to the original projection of $102,893 representing no variance. |
| Project Progress Summary: | The project is complete and was placed in service December 1998. |
| Project Projections: | Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $100,321. |

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Phillips Oil Tank No. 1 Upgrade

**Project Description:**

The Phillips Oil Tank No. 1 Upgrade is a 1,300,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, applying a coating to the internal floor and 30 inches up the tank wall, installing a spill containment for piping fittings and valves surrounding the tank, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

**Project Accomplishments:**

| | |
|---|---|
| Project Fiscal Expenditures: | The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $7,350 compared to the original projection of $7,350 representing no variance. |
| Project Progress Summary: | The project is complete and was placed in service October 1998. |
| Project Projections: | Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $7,102. |

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Phillips Oil Tank No. 4 Upgrade

**Project Description:**

The Phillips Oil Tank No. 4 Upgrade is a 57,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, applying a coating to the internal floor and 30 inches up the tank wall, installing a spill containment for piping fittings and valves surrounding the tank, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

**Project Accomplishments:**

| | |
|---|---|
| Project Fiscal Expenditures: | The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $11,563 compared to the original projection of $11,563 representing no variance. |
| Project Progress Summary: | The project is complete and was placed in service October 1998. |
| Project Projections: | Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $11,165. |

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** $SO_2$ Emissions Allowances

**Project Description:**

The acid rain control title of the CAAA sets forth a comprehensive regulatory mechanism designed to control acid rain by limiting sulfur dioxide emissions by electric utilities. The CAAA requires reductions in $SO_2$ emissions in two phases. Phase I began on January 1, 1995 and applies to 110 mostly coal-fired utility plants containing about 260 generating units. These plants are owned by some 40 jurisdictional utility systems that are expected to reduce annual $SO_2$ emissions by as much as 4.5 million tons. Phase II began on January 1, 2000, and applies to virtually all existing steam-electric generating utility units with capacity exceeding 25 megawatts and to new generating utility units of any size. The EPA issues to the owners of generating units allowances (defined as an authorization to emit, during or after a specified calendar year, one ton of $SO_2$) equal to the number of tons of $SO_2$ emissions authorized by the CAAA. EPA does not assess a charge for the allowances it awards.

**Project Accomplishments:**

| | |
|---|---|
| Project Fiscal Expenditures: | The actual/estimated O&M for the period January 2004 through December 2004 is ($7,608,085) compared to the original projection of ($220,100) representing a variance of –3,356.6%. The significant variance is due to the magnitude of unanticipated proceeds from the sale of allowances associated with Hookers Point Station which created a credit balance that was then applied to the allowances consumed. |
| Project Summary: | $SO_2$ Emissions Allowances are being used by Tampa Electric to meet compliance standards for Phase I of the CAAA. |
| Project Projections: | Estimated O&M costs for the period January 2005 through December 2005 are projected to be ($176,817). |

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** National Pollutant Discharge Elimination System ("NPDES") Annual Surveillance Fees

**Project Description:**

Chapter 62-4.052, Florida Administrative Code ("F. A. C."), implements the annual regulatory program and surveillance fees for wastewater permits. These fees are in addition to the application fees described in Rule 62-4.050, F. A. C. Tampa Electric's Big Bend, Hookers Point, Polk Power and Gannon Stations are affected by this rule.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated O&M expense for the period January 2004 through December 2004 is $34,500 compared to the original projection of $43,700 representing a variance of -21.1%. This variance is due to the exemption for Hookers Point Station which is no longer in service.

Project Summary: NPDES Surveillance fees are paid annually for the prior year.

Project Projections: Estimated O&M costs for the period January 2005 through December 2005 are projected to be $34,500.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Gannon Thermal Discharge Study

**Project Description:**

This project is a direct requirement from the FDEP in conjunction with the renewal of Tampa Electric's Industrial Wastewater Facility Permit under the provisions of Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code which constitute authorization for the company's Gannon Station facility to discharge to waters of the State under the NPDES. The FDEP permit is Permit No. FL0000809. Specifically, Tampa Electric is required to perform a 316(a) determination for Gannon Station to ensure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife with in the primary area of study. The project will have two facets: 1) develop the plan of study and identify the thermal plume, and 2) implement the plan of study through appropriate sampling to make the determination if any adverse impacts are occurring. The plan of study will be developed in 2001 with the bulk of the sampling and reporting occurring in 2002 and 2004.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated O&M expense for the period January 2004 through December 2004 is $152,526 compared to the original projection of $250,000 which represents a variance of –39.0%. This variance is primarily due to minimal spending until the sampling plan for the study is approved by the Department of Environmental Protection which is expected to occur in the late third or early fourth quarter of 2004.

Project Summary: This project was approved by the Commission in Docket No. 010593-EI on September 4, 2001. Work commenced during the 3rd quarter of 2001, however, unanticipated delays associated with the sample plan approval have occurred with FDEP. The project is expected to continue through at least 2005.

Project Projections: Estimated O&M costs for the period January 2005 through December 2005 are projected to be $500,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Polk $NO_x$ Emissions Reduction

**Project Description:**

This project is designed to meet a lower $NO_x$ emissions limit established by the FDEP for Polk Unit 1 by July 1, 2004. The lower limit of 15 parts per million by volume dry basis at 15 percent $O_2$ is specified in FDEP Permit No. PSD-FL-194F issued February 5, 2002. The project will consist of two phases: 1) the humidification of syngas through the installation of a syngas saturator; and 2) the modification of controls and the installation of additional guide vanes to the diluent nitrogen compressor.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $229,846 as compared to the original projection of $243,339 resulting in a variance of –5.5%. This variance was due a lower plant-in-service base for the calculation of the depreciation expense and return on average net investment than originally projected.

The actual/estimated O&M for the period January 2004 through December 2004 is $23,201 compared to the original projection of $32,800 which represents a variance of -29.3%. This variance was due to a lower amount of maintenance to the reverse osmosis system and saturator than originally projected.

Project Summary: The project was placed in service January 2004.

Project Projections: Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $225,889.

Estimated O&M costs for the period January 2005 through December 2005 are projected to be $33,600.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Bayside SCR Consumables

**Project Description:** This project is necessary to achieve the $NO_x$ emissions limit of 3.5 parts per million established by the FDEP Consent Final Judgment and the EPA Consent Decree for the natural gas-fired Bayside Power Station. To achieve this $NO_x$ limit, the installation of selective catalytic reduction (SCR) systems is required. An SCR system requires consumable goods – primarily anhydrous ammonia – to be injected into the catalyst bed in order to achieve the required $NO_x$ emissions limit. Principally, the project is designed to capture the cost of consumable goods necessary to operate the SCR systems.

**Project Accomplishments:**

| | |
|---|---|
| Project Fiscal Expenditures: | The actual/estimated O&M expense for the period January 2004 through December 2004 is $69,541 compared to the original projection of $243,000 resulting in a variance of -71.4%. This variance was due to a lower running rate for the units than originally projected. Additionally, the units are operating much cleaner than originally projected; therefore, a lower amount of ammonia is projected to be consumed. |
| Project Summary: | This project was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. As an O&M project, expenses are ongoing annually. |
| Project Projections: | Estimated O&M costs for the period January 2005 through December 2005 are projected to be $115,000. |

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Unit 4 SOFA

**Project Description:** This project is necessary to assist in achieving the $NO_x$ emissions limit established by the FDEP Consent Final Judgment and the EPA Consent Decree for Big Bend Unit 4. A separated overfire air (SOFA) system stages secondary combustion air to prevent $NO_x$ formation that would otherwise require removal by post-combustion technology. In-furnace combustion control through a SOFA system is the most cost-effective means to reduce $NO_x$ emissions prior to the application of these technologies. Costs associated with the SOFA system will entail capital expenditures for equipment installation and subsequent annual maintenance.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $304,949 compared to the original projection of $423,634 resulting in a variance of -28.0%. This variance was due to the competitive bid process and overall project management that resulted in a reduction of actual expenditures from the projected amount.

The actual/estimated O&M for the period January 2004 through December 2004 is $50,000 compared to the original projection of $50,000 which represents no variance.

Project Summary: This project was approved by the Commission in Docket No. 030226-EI, Order No. PSC-03-0684-PAA-EI, issued June 6, 2004. This project is projected to be placed in service August 2004.

Project Projections: Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $357,820.

Estimated O&M costs for the period January 2005 through December 2005 are projected to be $50,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Unit 1 Pre-SCR

**Project Description:** In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of $NO_x$ emissions at Big Bend Station on a per unit basis at prescribed times from 2007 through 2010. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet $NO_x$ emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet $NO_x$ concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 1 Pre-SCR technologies include a neural network system, secondary air controls and windbox modifications.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $11,354. This project commenced in July 2004; therefore, no variance can be calculated.

Project Summary: A petition was filed on July 15, 2004 for approval of cost recovery for four new environmental compliance programs - Big Bend Unit 4 SCR, Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR. These programs have been assigned Docket No. 040750-EI. The Commission staff recommendation for this docket is due on September 9, 2004, the Agenda Conference is scheduled for September 21, 2004 and the final order in this docket is scheduled to be issued October 11, 2004.

Project Projections: Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $103,945.

Estimated O&M costs for the period January 2005 through December 2005 are projected to be $27,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Unit 2 Pre-SCR

**Project Description:** In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of $NO_x$ emissions at Big Bend Station on a per unit basis at prescribed times from 2007 through 2010. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet $NO_x$ emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet $NO_x$ concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 2 Pre-SCR technologies include secondary air controls and windbox modifications.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $16,325. This project commenced in July 2004; therefore, no variance can be calculated.

Project Summary: A petition was filed on July 15, 2004 for approval of cost recovery for four new environmental compliance programs - Big Bend Unit 4 SCR, Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR. These programs have been assigned Docket No. 040750-EI. The Commission staff recommendation for this docket is due on September 9, 2004, the Agenda Conference is scheduled for September 21, 2004 and the final order in this docket is scheduled to be issued October 11, 2004.

Project Projections: Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $96,644.

Estimated O&M costs for the period January 2005 through December 2005 are projected to be $23,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Unit 3 Pre-SCR

**Project Description:** In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of $NO_x$ emissions at Big Bend Station on a per unit basis at prescribed times from 2007 through 2010. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet $NO_x$ emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet $NO_x$ concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 3 Pre-SCR technologies include a neutral network system, secondary air controls, windbox modifications and primary coal/air flow controls.

**Project Accomplishments:**

Project Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2004 through December 2004 is $12,713. This project commenced in July 2004; therefore, no variance can be calculated.

Project Summary: A petition was filed on July 15, 2004 for approval of cost recovery for four new environmental compliance programs - Big Bend Unit 4 SCR, Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR. These programs have been assigned Docket No. 040750-EI. The Commission staff recommendation for this docket is due on September 9, 2004, the Agenda Conference is scheduled for September 21, 2004 and the final order in this docket is scheduled to be issued October 11, 2004.

Project Projections: Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $121,751.

Estimated O&M costs for the period January 2005 through December 2005 are projected to be $66,000.

**Tampa Electric Company**
**Environmental Cost Recovery Clause**
**January 2005 through December 2005**
**Description and Progress Report for**
**Environmental Compliance Activities and Projects**

**Project Title:** Big Bend Unit 4 SCR

**Project Description:** In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of $NO_x$ emissions at Big Bend Station on a per unit basis at prescribed times from 2007 through 2010. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet $NO_x$ emissions requirements.

**Project Accomplishments:**

Project Fiscal Expenditures: Based on the Commission's previous ruling in Docket No. 980693-EI, Tampa Electric will not seek ECRC recovery of capital costs for this project until mid-2007, the expected in service date for the project. At that time, the associated depreciation expense and allowance for funds used during construction will be requested for ECRC recovery.

Project Summary: A petition was filed on July 15, 2004 for approval of cost recovery for four new environmental compliance programs - Big Bend Unit 4 SCR, Big Bend Unit 1 Pre-SCR, Big Bend Unit 2 Pre-SCR and Big Bend Unit 3 Pre-SCR. These programs have been assigned Docket No. 040750-EI. The Commission staff recommendation for this docket is due on September 9, 2004, the Agenda Conference is scheduled for September 21, 2004 and the final order in this docket is scheduled to be issued October 11, 2004.

Project Projections: Estimated depreciation plus return for the period January 2005 through December 2005 is projected to be $0.

Estimated O&M costs for the period January 2005 through December 2005 are projected to be $0.

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
**January 2005 to December 2005**

| Rate Class | (1) Average 12 CP Load Factor at Meter (%) | (2) Projected Sales at Meter (kWh) | (3) Projected Avg 12 CP at Meter (kW) | (4) Demand Loss Expansion Factor | (5) Energy Loss Expansion Factor | (6) Projected Sales at Generation (kWh) | (7) Projected Avg 12 CP at Generation (kW) | (8) Percentage of kWh Sales at Generation (%) | (9) Percentage of 12 CP Demand at Generation (%) | (10) 12 CP & 1/13 Allocation Factor (%) |
|---|---|---|---|---|---|---|---|---|---|---|
| RS, RST | 55.19% | 8,803,380,000 | 1,820,895 | 1.0576287 | 1.0472374 | 9,219,228,782 | 1,925,831 | 46.08% | 55.55% | 54.82% |
| GS, GST, TS | 61.70% | 1,066,948,000 | 197,403 | 1.0576287 | 1.0472374 | 1,117,347,849 | 208,779 | 5.58% | 6.02% | 5.99% |
| GSD, GSDT | 76.55% | 5,324,964,000 | 794,086 | 1.0565215 | 1.0466330 | 5,573,283,046 | 838,969 | 27.85% | 24.20% | 24.47% |
| GSLD, GSLDT, SBF | 83.61% | 2,303,504,000 | 314,504 | 1.0444011 | 1.0358878 | 2,386,171,691 | 328,468 | 11.93% | 9.48% | 9.67% |
| IS1, IST1, SBI1, SBIT1, IS3, IST3, SBI3 | 106.24% | 1,471,473,000 | 158,110 | 1.0205430 | 1.0173252 | 1,496,966,564 | 161,358 | 7.48% | 4.65% | 4.87% |
| SL/OL | 781.26% | 205,941,000 | 3,009 | 1.0576287 | 1.0472374 | 215,669,117 | 3,182 | 1.08% | 0.09% | 0.16% |
| TOTAL | | 19,176,210,000 | 3,288,007 | | | 20,008,667,049 | 3,466,587 | 100.00% | 100.00% | 100.00% |

Notes: (1) Average 12 CP load factor based on actual 2003 load research data
(2) Projected kWh sales for the period January 2005 to December 2005
(3) Calculated: (Column 2) / (8,760 hours x Column 1)
(4) Based on actual 2003 load research data
(5) Based on actual 2003 load research data
(6) Column 2 x Column 5
(7) Column 3 x Column 4
(8) Column 6 / Total Column 6
(9) Column 7 / Total Column 7
(10) Column 8 x 1/13 + Column 9 x 12/13



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 6
PAGE 1 0F 1
FORM 42-6P
FILED: SEPTEMBER 3, 2004

**Tampa Electric Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
**January 2005 to December 2005**

| Rate Class | (1) Percentage of kWh Sales at Generation (%) | (2) 12 CP & 1/13 Allocation Factor (%) | (3) Energy-Related Costs ($) | (4) Demand-Related Costs ($) | (5) Total Environmental Costs ($) | (6) Projected Sales at Meter (kWh) | (7) **Environmental Cost Recovery Factors (¢/kWh)** |
|---|---|---|---|---|---|---|---|
| RS, RST | 46.08% | 54.82% | 8,863,857 | 304,399 | 9,168,256 | 8,803,380,000 | **0.104** |
| GS, GST, TS | 5.58% | 5.99% | 1,073,358 | 33,261 | 1,106,619 | 1,066,948,000 | **0.104** |
| GSD, GSDT | 27.85% | 24.47% | 5,357,170 | 135,874 | 5,493,044 | 5,324,964,000 | **0.103** |
| GSLD, GSLDT, SBF | 11.93% | 9.67% | 2,294,831 | 53,695 | 2,348,526 | 2,303,504,000 | **0.102** |
| IS1, IST1, SBI1, SBIT1, IS3, IST3, SBI3 | 7.48% | 4.87% | 1,438,838 | 27,042 | 1,465,880 | 1,471,473,000 | **0.100** |
| SL/OL | 1.08% | 0.16% | 207,747 | 888 | 208,635 | 205,941,000 | **0.101** |
| TOTAL | 100.00% | 100.00% | 19,235,801 | 555,269 | 19,791,070 | 19,176,210,000 | **0.103** |

Notes: (1) From Form 42-6P, Column 8
(2) From Form 42-6P, Column 10
(3) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(4) Column 2 x Total Demand Jurisdictional Dollars from Form 42-1P, line 5
(5) Column 3 + Column 4
(6) From Form 42-6P, Column 2
(7) Column 5 / Column 6 x 100



EXHIBIT NO. _____
DOCKET NO. 040007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 7
PAGE 1 OF 1
FORM 42-7P
FILED: SEPTEMBER 3, 2004

# Exhibit to the Testimony of James O. Vick

## Exhibit (JOV-1)_____


| Enclosed Documentation | Page |
|---|---|
| FDEP letter to Gulf Power dated August 10, 2004 | 1 |
| Plant Smith Consumptive Use Permit | 3 |
| NWFWMD correspondence to Gulf Power dated August 18, 2004 | 9 |
| U.S. Fish and Wildlife Service correspondence dated August 25, 2004 | 10 |
| City of Destin Ordinance Number 03-40-LC | 11 |
| Bay County Ordinance Number 02-07 | 20 |



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040007-EI EXHIBIT NO. 14
COMPANY/ Gulf Power Co.
WITNESS: J. O. Vick (JOV-1)
DATE: 11-08-04

Jeb Bush
Governor

# Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

August 10, 2004

James O. Vick
Director, Environmental Affairs
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0328

Re: Crist Electric Generating Plant
FDEP/Gulf Power Ozone Reduction Agreement

Dear Mr. Vick:

Thank you for your letter dated April 30, 2004, outlining Gulf Power Company's ("Gulf Power") plans and draft schedule for implementing air pollution controls on Unit 6 of the Crist facility pursuant to the Ozone Reduction Agreement ("Agreement") entered between the Florida Department of Environmental Protection and Gulf Power. Based upon your letter, as well as conversations in late May of this year during a site visit, it is my understanding that Gulf Power will be installing and operating selective non-catalytic reduction ("SNCR") technology, as well as a low $NO_x$ burner/overfire air system, on Unit 6 by no later than May 1, 2006. In the event additional $NO_x$ controls are required on Units 4 and/or 5 to achieve the $NO_x$ emission limit of 0.2 lb/mmBtu as outlined in the Agreement, it is my understanding SNCR would be installed on Units 4 and 5 in the fall of 2005 and spring of 2006, respectively.

After reviewing the Agreement, FDEP concurs that the SNCR, low $NO_x$ burner/overfire air technologies for Unit 6, and Units 4 and 5 if necessary, meet the intent of the Agreement and are prudent for purposes of (a) ensuring that the Crist facility supports the Escambia/Santa Rosa/Bay County area's compliance with the 8-hour ozone ambient air quality standard and (b) authorizing related cost recovery pursuant to Section 366.8255(1)(d), Florida Statutes, as amended by the Florida Legislature in its 2002 session and signed into law by the Governor of the State of Florida.

We expect these upgrades to contribute significantly to improved air quality in the Pensacola region. Because of Gulf Power's commitment to ozone reduction, Pensacola is on a fast track for important air quality improvements, which is tremendous news for the environment, economy, and community of Northwest Florida. Please contact me at (850) 488-0114 if you have any questions regarding this matter.

Sincerely,

Michael G. Cooke, Director
Division of Air Resource Management

MGC/bja

# Northwest Florida Water Management District

81 Water Management Drive, Havana, Florida 32333-4712
*(U.S. Highway 90, 10 miles west of Tallahassee)*

(850) 539-5999 • (Suncom) 771-2080 • (Fax) 539-4380

Douglas E. Barr
*Executive Director*


April 1, 2002

Gulf Power, Inc.
Lansing Smith Electric Generating Plant
One Energy Place
Pensacola, FL 32520-0328

NOTICE OF AGENCY ACTION
Individual Water Use Permit No. 19850073
Consumptive Use Permit Application No. I 06108

Dear Permitee:

Your Individual Water Use Permit was approved by the Governing Board of the Northwest Florida Water Management District at a public hearing on March 28, 2002. The permit issued is subject to the terms and conditions set forth in the enclosed permit document. As you are legally responsible for compliance with the conditions of the permit please read the document thoroughly. Pay close attention to any condition(s) of the permit which require the one-time or periodic submittal of information to the District.

If the property where the withdrawal facility is located changes ownership, the permit must be transferred. A permit transfer request must be made on NWFWMD Form A2-F and approved by the Executive Director. If the permit is not transferred you may remain responsible for compliance with the conditions of the permit.

If you have any questions concerning the permit document or if the District can be of any other service, please let us know.

Sincerely,

F. E. Recio, Division Director
Division of Resource Regulation

FER/tp
Enclosure
cc: Richard M. Markey

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J. RUSSELL PRICE, *Chair, Tallahassee* · JOYCE ESTES, *Vice Chair, Eastpoint* · NANCYANN M. STUPARICH, *Secretary/Treasurer, Pensacola* · WAYNE BODIE, *DeFuniak Springs* · HULAN CARTER, *Chipley*
SHARON T. GASKIN, *Wewahitchka* · STEPHANIE HUGHES, *Panama City Beach* · L. E. MCMULLIAN, JR., *Sneads* · RICHARD P. PETERMANN, *Fort Walton Beach*

# NORTHWEST FLORIDA WATER MANAGEMENT DISTRICT
# INDIVIDUAL WATER USE PERMIT
(NWFWMD Form No. A2-E)

Permit granted to:

Gulf Power Company
Lansing Smith
Electric Generating Plant
One Energy Place
Pensacola, Florida 32520-0328
(Legal Name and Address)

Permit No.: 19850073 Modification

Date Permit Granted: March 28, 2002

Permit Expires On: March 29, 2007

Source Classification: Floridan Aquifer, North Bay, Recycled Water

Use Classification: Power Generation Public Supply

County: Bay Area: B

Location: Section _____ 1/4 Section _____

Application No.: I06108

Township 2 South Range 15 West

## Terms and standard conditions of this Permit are as follows:

1. That all statements in the application and in supporting data are true and accurate and based upon the best information available, and that all conditions set forth herein will be complied with. If any of the statements in the application and in the supporting data are found to be untrue and inaccurate, or if the Permittee fails to comply with all of the conditions set forth herein, then this Permit shall be revoked as provided by Chapter 373.243, Florida Statutes.

2. This Permit is predicated upon the assertion by the Permittee that the use of water applied for and granted is and continues to be a reasonable and beneficial use as defined in Section 373.019(4), Florida Statutes, is and continues to be consistent with the public interest, and will not interfere with any legal use of water existing on the date this Permit is granted.

3. This Permit is conditioned on the Permittee having obtained or obtaining all other necessary permit(s) to construct, operate and certify withdrawal facilities and the operation of water system.

4. This Permit is issued to the Permittee contingent upon continued ownership, lease or other present control of property rights in underlying, overlying, or adjacent lands. This Permit may be assigned to a subsequent owner as provided by Chapter 40A-2.351, Florida Administrative Code, and the acceptance by the transferee of all terms and conditions of the Permit.

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5. This Permit authorizes the Permittee to make a combined average annual withdrawal of 275,200,000* gallons of water per day, a maximum combined withdrawal of 276,880,000** gallons during a single day, and a combined monthly withdrawal of 8,531,200,000*** gallons. Withdrawals for the individual facilities are authorized as shown in the table below in paragraph six. However, the total combined amount of water withdrawn by all facilities listed in paragraph six shall not exceed the amounts identified above.

6. Individual Withdrawal Facility Authorization

| WITHDRAWAL POINT ID NO. | LOCATION SEC,TWN,RNG | GALLONS/DAY AVERAGE | GALLONS/DAY MAXIMUM |
|---|---|---|---|
| LSGP #1 (AAA6592) | Sec. 36, T2S, R15W | | 720,000 |
| LSGP #2 (AAA6591) | Sec. 36, T2S, R15W | | 720,000 |
| LSGP #3 (AAA6590) | Sec. 36, T2S, R15W | | 720,000 |
| LSGP #4 (AAD3491) | Sec. 25, T2S, R15W | | 720,000 |
| LSGP #5 (To Be Assigned) | Sec. 19, T2S, R15W | | 720,000 |
| LGSP 1A/NB | Sec. 36, T2S, R15W | | 68,256,000 |
| LGSP 1B/NB | Sec. 36, T2S, R15W | | 68,256,000 |
| LGSP 2A/NB | Sec. 36, T2S, R15W | | 68,256,000 |
| LGSP 2B/NB | Sec. 36, T2S, R15W | | 68,256,000 |
| * 1,200,000 Ground Water – 274,000,000 Surface Water<br>** 2,880,000 Ground Water – 274,000,000 Surface Water<br>*** 37,200,000 Ground Water – 8,494,000,000 Surface Water | | | |

7. The use of the permitted water withdrawal is restricted to the use classification set forth by the Permit. Any change in the use of said water shall require a modification of this Permit.

8. The District's staff, upon proper identification, will have permission to enter, inspect and observe permitted and related facilities in order to determine compliance with the approved plans, specifications and conditions of this Permit.

9. The District's staff, upon providing prior notice and proper identification, may request permission to collect water samples for analysis, measure static and/or pumping water levels and collect any other information deemed necessary to protect the water resources of the area.

10. The District reserves the right, at a future date, to require the Permittee to submit pumpage records for any or all withdrawal point(s) covered by this Permit.

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11. Permittee shall mitigate any significant adverse impact caused by withdrawals permitted herein on the resource and legal water withdrawals and uses, and on adjacent land use, which existed at the time of permit application. The District reserves the right to curtail permitted withdrawal rates if the withdrawal causes significant adverse impact on the resource and legal uses of water, or adjacent land use, which existed at the time of permit application.

12. Permittee shall not cause significant saline water intrusion or increased chloride levels. The District reserves the right to curtail permitted withdrawal rates if withdrawals cause significant saline water intrusion or increased chloride levels.

13. The District, pursuant to Section 373.042, Florida Statutes, at a future date, may establish minimum and/or management water levels in the aquifer, aquifers, or surface water hydrologically associated with the permitted withdrawals; these water levels may require the Permittee to limit withdrawal from these water sources at times when water levels are below established levels.

14. Nothing in this Permit should be construed to limit the authority of the Northwest Florida Water Management District to declare water shortages and issue orders pursuant to Section 373.175, Florida Statutes, or to formulate and implement a plan during periods of water shortage pursuant to Section 373.246, Florida Statutes, or to declare Water Resource Caution Areas pursuant to Chapters 40A-2.801, and 62-40.41, Florida Administrative Code

(a) In the event of a declared water shortage, water withdrawal reductions shall be made as ordered by the District.

(b) In the event of a declared water shortage or an area as a Water Resource Caution Area, the District may alter, modify or inactivate all or parts of this permit.

15. The Permittee shall properly plug and abandon any well determined unsuitable for its intended use, not properly operated and maintained, or removed from service. The well(s) shall be plugged and abandoned to District Standards in accordance with Section 40A-3.531, Florida Administrative Code.

16. Any Specific Permit Condition(s) enumerated in Attachment A are herein made a part of this Permit.

**Authorized Signature**
**Northwest Florida Water Management District**

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# ATTACHMENT
## Gulf Power Company
## Lansing Smith Electric Generating Plant

Individual Water Use Permit No. 19850073
Individual Water Use Application No. I06108

1. The Permittee shall record the data required on the Water Use Summary Reporting Form, NWFWMD A2-I, and submit copies to the District by January 31 of each year. The withdrawals shall be reported separately by source (ground water, surface, and recycled). The ground and surface water withdrawals shall also be provided as an aggregate. The first report is due by January 31, 2003.

2. The Permittee, by January 31, April 30, July 31, and October 31 of each year, shall report the following information as specified below:

   a. Water quality results from tests conducted on each production well of the system during the first two weeks of the months of January, April, July, and October as appropriate to the reporting period. The water quality analysis shall test for the following chemical concentrations: chloride, sodium, sulfate, bicarbonate, carbonate, calcium, magnesium, potassium, and total dissolved solids. Prior to sampling, the Permittee shall purge approximately three to five well volumes from each well, and shall report with each set of test results, the duration of purging, purge volume, and purge rates used.

   b. Static water level data for each production well as recorded during the first two weeks of January, April, July, and October as appropriate to the reporting period. The Permittee shall contact the District for assistance in designing the method and specifics of data collection. The water level data shall be referenced to mean sea level.

   The next water use, water quality and water level reports are due by January 31, 2003.

3. The Permittee shall continue to return approximately 95% or more of the surface water withdrawn.

4. The Permittee, at the time of construction, shall install an in-line totaling flow meter at the well head of proposed well LSGP #5. The Permittee shall install and maintain in working order in-line totaling flow meters on all other ground water wells.

5. The Permittee shall not exceed a withdrawal rate of 2,000 gallons per minute from the Floridan aquifer. The Permittee, at the time that LGSP #5 is operational, shall implement the pumping scenario identified in the ground water modeling analysis whereby LGSP #4 and #5 are operated as primary wells and LGSP #1 and #2 are operated as backup and emergency supply wells.

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6. The Permittee shall, at the time LGSP #5 becomes operational, abandon and properly plug LGSP #3 with cement grout from bottom of well to land surface in accordance with Chapter 40A-3.531, F.A.C., Abandoned Well Plugging.

7. The Permittee shall develop a plan for the implementation of water conservation and efficiency measures at the plant. The findings of the plan, along with a timetable for implementation, shall be submitted to the District no later than July 31, 2003.

8. The Permittee shall mitigate impacts attributable to the authorized withdrawal that interfere with users of water in the vicinity of Gulf Power's wells. The Permittee shall report the occurrence of any such impacts to the District and shall identify the mitigation action undertaken to address the impacts.

9. The Permittee, when corresponding with the District (e.g., pumping reports), shall reference its wells by the Florida Unique Identification Number.

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2.12.4


# Northwest Florida Water Management District

Division of Resource Regulation
152 Water Management Drive, Havana, Florida 32333-4711
*(U.S. Highway 90, 10 miles west of Tallahassee)*
(850) 539-5999 • (Suncom) 793-5999 • (Fax) 539-2777

Douglas E. Barr
*Executive Director*


August 18, 2004

Mr. Mike Markey
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0328

RE: Individual Water Use Permit No. 19850073
Specific Condition No. 7

Dear Mr. Markey:

The District understands that Gulf Power has implemented a water conservation plan in accordance with Specific Condition No. 7 of their consumptive use permit. In a 2004 submittal to the District, Gulf Power proposed the replacement of the laboratory sample cooling system with a closed loop chiller. The plant estimates that installation of the new system could reduce water use by approximately 80,000 gallons per day. This being the case, the District agrees that this would be a valid project to pursue for continued implementation of the required water conservation effort.

Sincerely,

Angela Chelette, Chief
Bureau of Ground Water Regulation

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JOYCE ESTES, Chair, Eastpoint
L. E. MCMULLIAN, Vice Chair, Sneads
STEPHANIE H. BLOYD, Secretary/Treasurer, Panama City Beach
LOIS BENSON, Pensacola
WAYNE BODIE, DeFuniak Springs
PAUL BRADSHAW, Havana
HULAN CARTER, Chipley
SHARON T. GASKIN, Wewahitchka
RICHARD PETERMANN, Fort Walton Beach

IN REPLY REFER TO:

# United States Department of the Interior

**FISH AND WILDLIFE SERVICE**
Field Office
1601 Balboa Avenue
Panama City, FL 32405-3721

Tel: (850) 769-0552
Fax: (850) 763-2177
August 25, 2004

Ms. Sondra Perry
Gulf Power (faxed)
Panama City, Florida

Dear Ms. Perry:

Per our conversation this morning I have listed below the Gulf Power leased lighting that needs shielding along Panama City Beach in Bay County, Florida. The shielding will help keep the beaches dark for sea turtle nesting and hatching. I have also indicated what streetlights need to be shielded immediately and those that can be done in the next 60 days.

Streetlight Location
**Needs shielding ASAP**
14th Street and Front Beach Road (near 20107 FBR)
**Can be shielded in the next 60 days**
Nautilus Street and Front Beach Road (between 13623 and 14401 FRB, Bid-a-Wee Beach)
Anemone Street and Front Beach Road (between 13623 and 14401 FRB, Bid-a-Wee Beach)
Dolphin Street and Front Beach Road (between 13623 and 14401 FRB, Bid-a-Wee Beach)
Tarpon Street and Front Beach Road (between 13623 and 14401 FRB, Bid-a-Wee Beach)
Argonaut Street and Front Beach Road (between 13623 and 14401 FRB, Bid-a-Wee Beach)
Petrel Street and Front Beach Road (between 13623 and 14401 FRB, Bid-a-Wee Beach)
Albatross Street and Front Beach Road (between 13623 and 14401 FRB, Bid-a-Wee Beach)
Crane Street and Front Beach Road (between 13623 and 14401 FRB, Bid-a-Wee Beach)
Streetlight between 20011 and 20015 Front Beach Road
Streetlight at 22025 Front Beach Road
Streetlight at 5025 Surf Drive
Streetlights between 10716 and 10519 Front Beach Road

Please call me at ext. 229 if you have any questions regarding the list.

Sincerely yours,

Lorna Patrick
Fish and Wildlife Biologist

ORDINANCE NO. 03-40-LC

AN ORDINANCE OF THE CITY OF DESTIN, FLORIDA, RELATING TO THE REGULATION OF OUTDOOR LIGHTING TO PROTECT MARINE TURTLES NESTING IN DESTIN, FLORIDA; PROVIDING FOR AUTHORITY; PROVIDING FOR FINDINGS OF FACT; PROVIDING FOR AMENDMENTS TO ARTICLE 3, SECTION 3.00.00 DEFINITIONS; PROVIDING FOR AMENDMENTS TO THE LAND DEVELOPMENT CODE, ARTICLE 7, BY CREATING SECTION 7.17.00. OUTDOOR LIGHTING STANDARDS; PROVIDING FOR THE CREATION OF ARTICLE 7, SECTION 7.17.01. OUTDOOR LIGHTING STANDARDS FOR THE MARINE TURTLE CONSERVATION ZONE; PROVIDING FOR THE CREATION OF ARTICLE 7, SECTION 7.17.01.A. PURPOSE AND INTENT; PROVIDING FOR THE CREATION OF ARTICLE 7, SECTION 7.17.01.B. STANDARDS FOR NEW CONSTRUCTION ACTIVITIES; PROVIDING FOR THE CREATION OF ARTICLE 7, SECTION 7.17.01.C. STANDARDS FOR EXISTING LIGHTING; PROVIDING FOR THE CREATION OF ARTICLE 7, SECTION 7.17.01.D. PUBLIC AWARENESS; PROVIDING FOR THE CREATION OF ARTICLE 7, SECTION 7.17.02 ENFORCEMENT AND PENALTIES; PROVIDING FOR INCORPORATION INTO THE LAND DEVELOPMENT CODE; PROVIDING FOR INTERPRETATION; PROVIDING FOR CONFLICTING PROVISIONS; PROVIDING FOR SEVERABILITY; AND PROVIDING FOR AN EFFECTIVE DATE.

NOW, THEREFORE, BE IT ORDAINED BY THE CITY OF DESTIN, FLORIDA AS FOLLOWS:

SECTION 1. AUTHORITY. The authority for the enactment of this Ordinance is Section 1.01(h) of the City Charter and Section 166.021, Florida Statutes.

SECTION 2: FINDINGS OF FACT.

WHEREAS, Destin, Florida is a coastal community with an extensive shoreline on the Gulf of Mexico; and

WHEREAS, Destin's beaches are a marine turtle nesting location; and

WHEREAS, Destin's shoreline is developed or will be developed with numerous structures on the shoreline in close proximity to marine turtle nests; and

WHEREAS, it is the City of Destin's intent to protect marine turtles to the fullest possible extent; and

WHEREAS, artificial lighting has been proven to adversely affect marine turtles; and

WHEREAS, it is Destin City Council's intention to ensure protection of marine turtles by regulating lighting in the Marine Turtle Conservation Zone and incorporating these regulations into the Destin Land Development Code; and

WHEREAS, a public hearing has been conducted after due public notice by the Destin Local Planning Agency and its recommendations reported to the City Council; and

WHEREAS, a public hearing has been conducted by the City Council after due public notice; and

WHEREAS, the City Council has determined that this ordinance is consistent with the adopted comprehensive plan and is in the best interests of the City and its citizens.

NOTE. *Language in sections 3 and 4 of this ordinance that is ~~struck through~~ is language proposed to be deleted, underlined language is language proposed to be added, language that is not ~~struck through~~ or underlined is not to be changed, and * * * represents sections of the Land Development Code that have been skipped and remain unchanged.*

SECTION 3: DEFINITIONS AMENDMENTS.

Article 3, Section 3.00.00, *Definitions*, of the City of Destin's Land Development Code is hereby amended to add the following:

3.00.00. Definitions.

The purpose of this article is to provide definitions applicable to the land development code. The following terms supplement those contained in the glossary of the foundation document:

* * *

*Artificial light or artificial lighting:* Means the light emanating from any human made device.

* * *

*Beach:* Means the area of white, sandy beach between the vegetation line and the waters of the Gulf of Mexico.

* * *

*Bug.* Type light means any yellow colored like bulb that is marketed as being specifically treated so as to reduce the attraction of bugs to the light.

* * *

*Coastal construction activities:* Means any work or development in the conservation zone.

* * *

*Coastal construction control line (CCCL):* ~~The most landward line for jurisdiction established by the department of natural~~ resources (DNR) Means the portion of the coastal construction line established pursuant to the provisions of section 161.053 Florida Statues that lies with the City of Destin.

* * *

*Cumulative illuminated:* Means illuminated by numerous artificial light sources that as a group illuminate any portion of the beach.

* * *

*Directly illuminated (Beach Lighting):* Means illuminated as a result of glowing element(s), lamp(s), globe(s), or reflector(s), of any artificial light source, which is visible to an observer on the beach.

* * *

*Dune:* Means a mound or ridge of loose sediments, usually sand-sized, lying landward of the beach and deposited by any natural or artificial mechanism.

* * *

*Frontal dune:* Means the first natural or man-made mound or bluff of sand which is located landward of the beach and which has sufficient vegetation, height, continuity, and configuration to offer protective value.

* * *

*Ground-level barrier:* Means any vegetation, natural feature or artificial structure arising from the ground, which prevents beachfront lighting from shining directly onto the beach-dune system.

* * *

*Hatchling:* Means any species of marine turtle, within or outside of a nest, and that has recently hatched from an egg.

* * *

*Indirectly illuminated (Beach Lighting):* Means illuminated as a result of the glowing element(s), lamp(s), globe(s), or reflector(s), of an artificial light source that is not visible to an observer on the beach.

* * *

*Low-pressure sodium luminaire (LPS):* Means an electric discharge lamp containing sodium, neon, and argon, that when illuminated appears amber-yellow.

* * *

*Marine turtle.* Means any marine-dwelling reptile of the families Cheloniidae or Dermochelyidae found in Florida waters or using the beach as nesting habitat, including the species: Caretta caretta (loggerhead); Chelonia mydas (green); Dermachelys coriacea (leatherback); Eretmochelys imbricata (hawksbill); and Lepidochelys Kempi (Kemp's ridley). For purposes of this Code, marine turtles are synonymous with sea turtles.

* * *

*Marine turtle conservation zone:* Includes all land abutting the "beach" within 300 feet of the Mean High Water Line starting at the tip of the south side of the entrance of the Destin Harbor south and then eastward to the Walton County line.

* * *

*Nest:* Means an area where marine turtle eggs have been naturally deposited or subsequently relocated.

* * *

*Nesting season:* Means the period from May 1 through October 31 of each year as defined by F.A.C. 62b 55.002(17) for all counties.

* * *

*Nighttime:* Means the locally effective time period between sunset and sunrise.

* * *

*Pole lighting:* Means a light fixture set on a base or pole, which raises the source of light higher than twenty four (24) inches off the ground.

* * *

*Shield (Beach Lighting):* Means a non-reflective covering, canopy or other such device fitted over and extended below a light source preventing light from illuminating the beach.

* * *

*Tinted glass:* Means any glass treated to achieve an industry-approved, inside-to-outside light transmittance value of 45% or less. Such transmittance is limited to the visible spectrum (400 to 700 nanometers) and is measured as the percentage of light that is transmitted through the glass.

SECTION 4: AMENDING LAND DEVELOPMENT CODE ARTICLE 7, BY CREATING SECTION 7.17.00 OUTDOOR LIGHTING STANDARDS.

Article 7, *Land Use, Type, Density, Intensity, Zoning and Regulatory Controls*, of the City of Destin's Land Development Code is hereby amended by creating Section 7.17.00., *Outdoor Lighting Standards*, as follows:

**7.17.00. Outdoor lighting standards.**

7.17.01. *Outdoor lighting standards for the marine turtle conservation zone.*

A. *Purpose and Intent.* This ordinance is intended to protect marine turtle hatchlings from the adverse effects of artificial lighting to provide overall improvement in nesting habitat degraded by light pollution, and to increase successful nesting activities and production of hatchlings on the beaches located within the Marine Turtle Conservation Zone within the City Limits of the City of Destin. The provisions of section 7.17.00 apply during the nesting season as defined in Article 3, Section 3.00.00.

B. *Standards for new construction activities.* In order to provide the highest level of protection for nesting marine turtles and their hatchlings, the following standards for artificial light sources on all new coastal construction seaward of the Coastal Construction Control Line (CCCL) in the Marine Turtle Conservation Zone are adopted:

1. Exterior artificial lighting fixtures shall be designed for and positioned so that:

   a. The point source of light or any reflective surface of the light fixture is not directly visible from the beach;
   b. Areas seaward of the frontal dune are not directly or indirectly illuminated; and
   c. Areas seaward of the frontal dune are not cumulatively illuminated.

2. Exterior artificial light fixtures within direct line-of-sight of the beach will be permitted only if designed and installed completely shielded down light only fixtures or recessed fixtures having low wattage (i.e., 50 watts or less), "bug" type bulbs and non-reflective interior surface. Other fixtures that have appropriate shields, louvers, or cutoff features may also be used if they are in compliance with subsection (1) (a), (b), and (c) above.

3. Floodlights, up lights or spotlights that are directly visible from the beach, or which indirectly or cumulatively illuminate the beach are prohibited.

4. No lighting other than approved turtle friendly lights installed appropriately shall be allowed on dune walkovers.

5. Exterior lights used expressly for safety or security purposes must comply with subsections (1) (a) and (b) above and shall be limited to the minimum number of configurations required to achieve their functional role(s). The use of motion detector switches that keep lights off except when approached and that switch lights on for the minimum duration possible are required.

6. Only low intensity lighting shall be used in parking areas within line-of-sight of the beach. Such lighting shall be:

   a. Set on a base which raises source of light no higher than 48 inches off the ground; and

   b. Positioned or shielded so that the light is cast downward and the source of light or any reflective surface of light feature is not visible from the beach and does not directly or indirectly illuminate the beach.

7. Parking area lighting shall be shielded from the beach through the use of ground-level barriers. Ground-level barriers must not interfere with marine turtle nesting or hatchling emergence, or cause short or long-term damage to the beach/dune system.

8. Tinted glass shall be installed on all windows and glass doors on single or multi-story structures within line-of-sight of the beach.

9. Use of appropriately shielded low-pressure sodium vapor lamps and fixtures shall be required for high-intensity lighting applications such as lighting parking areas and roadways providing security, and similar applications.

10. Temporary lighting of construction sites during the marine turtle nesting season shall be restricted to the minimal amount necessary and shall incorporate all of the standards of this section.

11. Before granting any building permit, the Community Development Department shall determine that all proposed development complies in all respects with the standards imposed in this section.

12. Utility lease lighting shall comply to all respects with the standards imposed in this ordinance, with the exception that appropriated shielded, full-cut off-feature high-pressure sodium lights may be installed for utility lease lighting until the utility provider offers functional low-pressure sodium lighting.

C. *Standards for existing lighting.* In order to provide the highest level of protection for nesting marine turtles and their hatchlings, the following

standards for existing artificial light sources, including utility leased lighting, within the Marine Turtle Conservation Zone shall be brought into compliance by May 1, 2005:

1. Existing artificial light fixtures shall be repositioned, modified, disconnected, or removed so that:

   a. The point source of light or any reflected surface of the light fixture is not directly visible from the beach;

   b. Areas seaward of the frontal dune are not directly or indirectly illuminated; and

   c. Areas seaward of the frontal dune are not cumulatively illuminated.

2. Existing artificial light fixtures that are replaced for any reason shall comply with Sub-section B, Standards for New Construction Activities and the following measures shall be taken:

   a. Reposition fixtures so that the point source of light or any reflected surface of the light fixture is no longer visible from the beach;

   b. Replace fixtures having an exposed light source with fixtures containing recessed light sources or shields;

   c. Replace traditional light bulbs with yellow "bug" type bulbs not exceeding 50 watts;

   d. Replace non-directional fixtures with directional fixtures that point down and away from the beach;

   e. Replace fixtures having transparent or translucent coverings with fixtures having opaque shields covering an arc of at least 180 degrees and extending an appropriate distance below the bottom edge of the fixture on the seaward sides so that the light source of any reflective surface of the light fixture is not visible from the beach;

   f. Replace pole lamps with low profile, low-level luminaries so that the light source of any reflective surface of the light fixture is not visible from the beach;

   g. Replace incandescent, fluorescent, and high-intensity lighting with the lowest wattage low-pressure sodium-vapor lighting possible for the specific application;

   h. Plant or improve vegetation buffers between the light source and beach to screen light from the beach;

i. Permanently remove or permanently disable any fixture that cannot be brought into compliance with the provisions of these standards.

3. The following measures shall be taken as applicable to reduce or eliminate the negative effects of interior light emanating from doors and windows within line-of-sight of the beach:

a. Apply window tint or film that meets the standards tinted glass;

b. Rearrange lamps and other movable fixtures away from windows;

c. Use window treatment (i.e., blind, curtains) to shield interior light from the beach; and

d. Turn off unnecessary lights.

D. *Public awareness.* Any person submitting an application for coastal construction activities within a Marine Turtle Conservation Zone shall be informed of the existence of and the requirements concerning artificial lighting and marine turtle protection by the City of Destin's Community Development Department.

7.17.02. *Enforcement and penalties.* Any alleged violation of section 7.17.00 or any of its sub-sections shall be processed in accordance with the procedures set forth in the City's Code of Ordinances, Chapter 14, Article III Code Enforcement Board.

SECTION 5: INCORPORATION INTO LAND DEVELOPMENT CODE.

This ordinance shall be incorporated into the City of Destin's Land Development Code and any section or paragraph number or letter and any heading may be changed or modified as necessary to effectuate the foregoing.

SECTION 6. INTERPRETATION.

The provisions of this ordinance shall be liberally construed in order to effectively carry out its purpose. Where any provision of this ordinance refers to or incorporates another provision, ordinance, statute, rule, regulation, policy, official publication, or other party, it refers to the most current version, incorporating any amendments thereto or rescinded station thereof.

SECTION 7: CONFLICTING PROVISIONS.

Special Acts of the Florida Legislature applicable to the incorporated area of the City of Destin, City Ordinances and City Resolutions, or parts, thereof, in conflict with the provisions of this ordinance are hereby superceded by this ordinance to the extent of such conflict.

SECTION 8: SEVERABILITY.

Each separate provision of this ordinance is deemed independent of all other provisions herein so that if any portion or provision of this ordinance is declared invalid, all other provisions thereof shall remain valid and enforceable.

SECTION 9: EFFECTIVE DATE.

This ordinance shall become effective upon its adoption by the City Council and signature by the Mayor.

ADOPTED THIS 17th DAY OF FEBRUARY 2004.

By: _____
Craig H. Barker, Mayor

ATTEST:

SEAL

_____
Dandi S. Williams, City Clerk

The form and legal sufficiency of the foregoing has been reviewed and approved by the Land Use Attorney.

_____
Scott Shirley, City Land Use Attorney

First Reading: 2/2/04
Second Reading: 2/17/04

**ORDINANCE NO. 02-07**

**AN ORDINANCE OF BAY COUNTY, FLORIDA, ESTABLISHING A SEA TURTLE CONSERVATION ZONE AND LIGHTING ORDINANCE IN THE WESTERN BEACHES AREA OF UNINCORPORATED BAY COUNTY; PROVIDING FOR A PURPOSE AND APPLICABILITY; PROVIDING FOR DEFINITIONS; PROVIDING STANDARDS FOR NEW CONSTRUCTION ACTIVITIES; PROVIDING STANDARDS FOR EXISTING LIGHTING; PROVIDING FOR ENFORCEMENT AND PENALTIES; PROVIDING FOR INTERPRETATION; PROVIDING FOR SEVERABILITY AND PROVIDING FOR AN EFFECTIVE DATE.**

WHEREAS, Bay County, Florida, is a coastal community with an extensive shoreline on the Gulf of Mexico; and,

WHEREAS, Bay County's extensive shoreline is good habitat for sea turtle nesting and many sea turtles make their nests on Bay County's beaches; and,

WHEREAS, Bay County's shoreline is developed or will be developed with numerous structures on the shoreline in close proximity to sea turtle nests; and,

WHEREAS, structures which are built on or near the shoreline usually include some source of artificial lighting; and,

WHEREAS, scientific studies have determined that certain types of artificial lighting have a detrimental effect on nesting sea turtles and their hatchlings due to the disorientation that occurs when the sea turtle mistakes the artificial lighting as the reflection of the moon light from the waters of the Gulf of Mexico; and,

WHEREAS, the Bay County Board of County Commissioners (the "Board") is desirous of implementing this lighting ordinance with the intention that the detrimental effects of artificial lighting on sea turtles will be relieved; and,

WHEREAS, the Board desires to test the effects of this ordinance first in the limited area of the

westernmost beaches area of unincorporated Bay County with the intention to expand it to other areas of Bay County; provided that, the expected positive effects of the ordinance are realized;

NOW THEREFORE, BE IT ORDAINED by the Board of County Commissioners of Bay County, Florida:

**Section 1. PURPOSE AND APPLICABILITY**

(1) This purpose and intent of this ordinance is to protect threatened and endangered sea turtles along the Gulf of Mexico beaches in the western unincorporated area of Bay County from the westernmost municipal boundary of the City of Panama City Beach west to the Bay/Walton County boundary. This ordinance is intended to protect nesting sea turtles and sea turtle hatchlings from the adverse effects of artificial lighting, provide overall improvement in nesting habitat degraded by light, and to increase successful nesting activity and production of hatchlings on the beaches.

(2) The provisions of this ordinance apply during the nesting season. Note that "nesting season" is defined in Section 2.

**Section 2. DEFINITIONS**

(1) *Artificial light* or *artificial lighting* means the light emanating from a manmade point source (see *Point source of light*, below).

(2) *Beach* means the zone of unconsolidated material that extends landward from the mean low-water line to the place where there is a marked change in material or physiographic form, or to the line of permanent vegetation, usually the effective limit of storm waves.

(3) *Bug type light* means any yellow colored incandescent light bulb that is specifically treated in such a way so as to reduce the attraction of bugs to the light, but does not include bug killing devices.

(4) *Construction* means the carrying out of any building, clearing, filling, excavating or substantial improvement in the size or use of any structure or the appearance of any land. When appropriate to the context, the term "construction" refers to the act of constructing or the result of construction, and includes remodeling or reconstruction of existing buildings or structures.

(5) *Cumulatively illuminated* means illuminated by numerous artificial light sources that as a group illuminate any portion of the beach.

(6) *Directly illuminated* means illuminated by one or more point sources of light directly visible to an observer on the beach.

(7) *Dune* means a mound or ridge of loose sediments, usually sand-sized, lying landward of the beach and deposited by any natural or artificial mechanism.

(8) *Frontal dune* means the first natural or human-made mound or bluff of sand which is located landward of the beach and which has sufficient vegetation, height, continuity, and configuration to offer protective value.

(9) *Ground-level barrier* means any vegetation, natural feature or artificial structure rising from the ground which prevents beachfront lighting from shining directly onto the beach-dune system.

(10) *Hatchling* means any individual of a species of sea turtle, within or outside of a nest, that has recently hatched from an egg.

(11) *Indirectly illuminated* means illuminated by one or more point sources of light not directly visible to an observer on the beach.

(12) *Low-pressure sodium light* means an electric discharge lamp containing sodium, neon, and argon, that when illuminated appears amber-yellow.

(13) *Nest* means an area where sea turtle eggs have been naturally deposited or subsequently relocated by an authorized permittee of the Florida Department of Environmental Protection.

(14) *Nesting season* means the period from sunset until sunrise during May 1 through October 31 of each year.

(15) *Person* means individuals, firms, associations, joint ventures, partnerships, estates, trusts, syndicates, fiduciaries, corporations, and all other groups or combinations.

(16) *Point source of light* means a manmade source emanating light, including, but not limited to: incandescent, tungsten-iodine (quartz), mercury vapor, fluorescent, metal halide, neon, halogen, high-pressure sodium, low-pressure sodium light sources, as well as torches, camp and bonfires.

(17) *Pole lighting* means a light fixture set on a base or pole which raises the source of light higher than twenty four (24) inches off the ground.

(18) *Sea turtle* means any marine-dwelling reptile of the families Cheloniidae or Dermochelyidae found in Florida waters or using the beach as nesting habitat, including the species: *Caretta caretta* (loggerhead), *Chelonia mydas* (green), *Dermochelys coriacea* (leatherback), *Eretmochelys imbricata* (hawksbill), and *Lepidochelys kempi* (Kemp's ridley). For purposes of this rule, sea turtle is synonymous with marine turtle.

(19) *Sea Turtle Conservation Zone* means the beach area seaward of the Coastal Construction Control Line in the unincorporated area of Bay County from the westernmost municipal boundary of the City of Panama City Beach west to the Bay/Walton County boundary.

(20) *Shield* means a non-reflective covering, canopy or other such device fitted over and extended below a light source preventing light from illuminating the beach.

(21) *Turtle glass* means any tinted glass treated to achieve an industry-approved, inside-to-outside light transmittance value of 45% or less. Such transmittance is limited to the visible spectrum (400 to 700 nanometers) and is measured as the percentage of light that is transmitted through the glass.

## Section 3. STANDARDS FOR NEW CONSTRUCTION ACTIVITIES

In order to provide the highest level of protection for nesting sea turtles and their hatchlings, the following standards for artificial light sources on all new coastal construction in the Sea Turtle Conservation Zone are adopted:

(1) Exterior artificial light fixtures shall be designed and positioned so that:

(a) The point source of light or any reflective surface of the light fixture is not directly visible from the beach;

(b) Areas seaward of the frontal dune are not directly or indirectly illuminated; and

(c) Areas seaward of the frontal dune are not cumulatively illuminated.

(2) Exterior artificial light fixtures within direct line-of-sight of the beach will be permitted only

if designed and installed as follows:

(a) Completely shielded downlight only fixtures or recessed fixtures having bug lights not exceeding 50 watts and non-reflective interior surfaces are used. Other fixtures that have appropriate shields, louvers, or cutoff features may also be used if they are in compliance with subsection (1)(a), (b) and (c) above; and
(b) All fixtures are mounted as low in elevation as possible through the use of low-mounted wall fixtures, low bollards, and ground-level fixtures.

(3) Floodlights, uplights or spotlights that are directly visible from the beach, or which indirectly or cumulatively illuminate the beach, are prohibited.

(4) Exterior lights used expressly for safety or security purposes must comply with subsection 2(a) and shall be limited to the minimum number and configuration required to achieve their functional role(s). The use of motion detector switches that keep lights off except when approached and that switch lights on for the minimum duration possible are required.

(5) Only low intensity lighting shall be used in parking areas within line-of-sight of the beach. Such lighting shall be:

(a) Set on a base which raises the source of light no higher than 48 inches off the ground; and

(b) Positioned or shielded so that the light is cast downward and the source of light or any reflective surface of the light fixture is not visible from the beach and does not directly or indirectly illuminate the beach.

(6) Parking area lighting, and roadway lighting shall be shielded from the beach through the use of ground-level barriers. Ground-level barriers must not interfere with sea turtle nesting or hatchling emergence, or cause short or long term damage to the beach/dune system.

(7) Turtle glass shall be installed on all windows and glass doors of single or multi-story structures within line-of-sight of the beach.

(8) Use of appropriately shielded low-pressure sodium lights and fixtures will be encouraged for high-intensity lighting applications such as lighting parking areas and roadways, providing security, and similar applications.

(9) Temporary lighting of construction sites during the sea turtle nesting season shall be restricted to the minimal amount necessary and shall incorporate all of the standards of this section.

(10) Before granting any building permit, the Bay County Builders Services shall determine that all proposed construction complies in all respects with the standards imposed in this section.

(11) Utility leased lighting shall comply in all respects with the standards imposed in this

ordinance.

(12) No lighting shall be allowed on dune walkovers.

**Section 4. STANDARDS FOR EXISTING LIGHTING**

In order to provide the highest level of protection for nesting sea turtles and their hatchlings, the following standards for existing artificial light sources, including utility leased lighting, within the Sea Turtle Conservation Zone shall be brought into compliance by May 1, 2003:

(1) Existing artificial light fixtures shall be repositioned, modified, disconnected, or removed so that:

(a) The point source of light or any reflective surface of the light fixture is not directly visible from the beach;

(b) Areas seaward of the frontal dune are not directly or indirectly illuminated; and

(c) Areas seaward of the frontal dune are not cumulatively illuminated.

(2) Existing artificial light fixtures that are replaced for any reason shall comply with Section 3, Standards for New Construction Activities and the following measures shall be taken:

(a) Reposition fixtures so that the point source of light or any reflective surface of the light fixture is no longer visible from the beach;

(b) Replace fixtures having an exposed light source with fixtures containing recessed light sources or shields;

(c) Replace traditional light bulbs with bug lights not exceeding 50 watts;

(d) Replace non-directional fixtures with directional fixtures that point down and away from the beach;

(e) Replace fixtures having transparent or translucent coverings with fixtures having opaque shields covering an arc of at least 180 degrees and extending an appropriate distance below the bottom edge of the fixture on the seaward side so that the light source or any reflective surface of the light fixture is not visible from the beach;

(f) Replace pole lamps with low-profile, low-level luminaries so that the light source or any reflective surface of the light fixture is not visible from the beach;

(g) Replace incandescent, fluorescent, and high intensity lighting with the lowest wattage low-pressure sodium lighting possible for the specific application;

(h) Plant or improve vegetation buffers between the light source and the beach to screen light from the beach.

(i) Permanently remove or permanently disable any fixture which cannot be brought into compliance with the provisions of these standards.

(3) One or more of these voluntary measures as applicable, shall be encouraged to reduce or eliminate the negative effects of interior light emanating from doors and windows within line-of-sight of the beach:

(a) Apply window tint or film that meets the standards of turtle glass;

(b) Rearrange lamps and other moveable fixtures away from windows;

(c) Use window treatments (i.e., blinds, curtains) to shield interior lights from the beach; and

(d) Turn off unnecessary lights.

**Section 5. ENFORCEMENT AND PENALTIES**

The enforcement and penalties of this ordinance, shall be the same manner as provided in Section 125.69 Florida Statutes, as may be amended from time to time. Each day of any such violation shall constitute a separate and distinct offense. In addition to the Bay County Code Enforcement Office, the Department of Environmental Protection and the Florida Fish and Wildlife Conservation Commission (Marine Patrol) shall have authority to enforce the ordinance.

The Board, by Resolution, will require property owners that remit Tourist Development Council Bed Taxes within the Sea Turtle Conservation Zone to post a sign on their property informing renters of this ordinance and the provisions within it.

**Section 6. INTERPRETATION**

The provisions of this ordinance shall be construed in order to effectively carry out its purpose. Where any provision of this ordinance refers to or incorporates another provision, ordinance, statute, rule, regulation, policy, official publication, or other authority, it refers to the most current version, incorporating any amendments thereto or redesignation thereof.

**Section 7. SEVERABILITY**

If any section, subsection, sentence, clause or provision of this ordinance is held invalid by a court of competent jurisdiction, the remainder of the ordinance shall not be affected.

**Section 8. EFFECTIVE DATE**

This ordinance shall take effect as provided by law.

DONE AND ADOPTED this 21st day of May, 2002.

BOARD OF COUNTY COMMISSIONERS
OF BAY COUNTY, FLORIDA

CHAIRMAN

SEAL

ATTEST:

CLERK OF THE COURT
By: Tammy Norris
Deputy Clerk

Approved as to correctness
of form:
Burke & Blue, P.A.
Attorneys for Bay County

**Schedule 1A**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

| Line | | Period Amount ($) |
|---|---|---|
| 1 | End of Period Actual Total True-Up for the Period January 2003 - December 2003 (Schedule 2A, Line 5+6+10) | 840,298 |
| 2 | Estimated/Actual True-Up Amount approved for the period January 2003 - December 2003 (Order NO. PSC-03-1348-FOF-EI) | 209,163 |
| 3 | Final True-Up Amount to be refunded/(recovered) in the projection period January 2005 - December 2005 (Lines 1 - 2) | 631,135 |

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040007-EI EXHIBIT NO. 15
COMPANY/ Gulf Power
WITNESS. T.A. Davis (TAD-1)
DATE 11-09-04

Schedule 2A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

**Current Period True-Up Amount**
(in Dollars)

| Line | | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ECRC Revenues (net of Revenue Taxes) | 930,949 | 713,397 | 742,213 | 780,800 | 979,621 | 1,028,423 | 1,082,470 | 1,093,231 | 966,579 | 804,182 | 756,699 | 1,003,293 | 10,881,857 |
| 2 | True-Up Provision (Order No. PSC-02-1735-FOF-EI) | 52,770 | 52,770 | 52,770 | 52,770 | 52,770 | 52,770 | 52,770 | 52,770 | 52,770 | 52,770 | 52,770 | 52,777 | 633,247 |
| 3 | **ECRC Revenues Applicable to Period (Lines 1 + 2)** | 983,719 | 766,167 | 794,983 | 833,570 | 1,032,391 | 1,081,193 | 1,135,240 | 1,146,001 | 1,019,349 | 856,952 | 809,469 | 1,056,070 | 11,515,104 |
| 4 | Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| | a O & M Activities (Schedule 5A, Line 9) | 735,991 | 141,780 | 136,420 | 131,287 | 209,342 | 162,004 | 110,271 | 82,603 | 290,105 | 217,351 | 83,374 | 246,236 | 2,546,764 |
| | b Capital Investment Projects (Schedule 7A, Line 9) | 687,994 | 686,706 | 684,787 | 683,299 | 680,986 | 678,133 | 676,033 | 673,728 | 671,798 | 670,232 | 668,212 | 672,800 | 8,134,708 |
| | c **Total Jurisdictional ECRC Costs** | 1,423,985 | 828,486 | 821,207 | 814,586 | 890,328 | 840,137 | 786,304 | 756,331 | 961,903 | 887,583 | 751,586 | 919,036 | 10,681,472 |
| 5 | **Over/(Under) Recovery (Line 3 - Line 4c)** | (440,266) | (62,319) | (26,224) | 18,984 | 142,063 | 241,056 | 348,936 | 389,670 | 57,446 | (30,631) | 57,883 | 137,034 | 833,632 |
| 6 | Interest Provision (Schedule 3A, Line 10) | 658 | 328 | 219 | 158 | 188 | 301 | 486 | 779 | 934 | 896 | 838 | 881 | 6,666 |
| 7 | Beginning Balance True-Up & Interest Provision | 633,247 | 140,869 | 26,108 | (52,667) | (86,295) | 3,186 | 191,773 | 488,425 | 826,104 | 831,714 | 749,209 | 755,160 | 633,247 |
| | a Deferred True-Up from January 2002 - December 2002 (Order No. PSC-03-1348-FOF-EI) | 229,600 | 229,600 | 229,600 | 229,600 | 229,600 | 229,600 | 229,600 | 229,600 | 229,600 | 229,600 | 229,600 | 229,600 | 229,600 |
| 8 | True-Up Collected/(Refunded) (see Line 2) | (52,770) | (52,770) | (52,770) | (52,770) | (52,770) | (52,770) | (52,770) | (52,770) | (52,770) | (52,770) | (52,770) | (52,777) | (633,247) |
| 9 | End of Period Total True-Up (Lines 5 + 6 + 7 + 7a + 8) | 370,469 | 255,708 | 176,933 | 143,305 | 232,786 | 421,373 | 718,025 | 1,055,704 | 1,061,314 | 978,809 | 984,760 | 1,069,898 | 1,069,898 |
| 10 | Adjustments to Period Total True-Up Including Interest | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | **Current Period Total Net True-Up (Lines 9 + 10)** | 370,469 | 255,708 | 176,933 | 143,305 | 232,786 | 421,373 | 718,025 | 1,055,704 | 1,061,314 | 978,809 | 984,760 | 1,069,898 | 1,069,898 |

Schedule 3A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

**Interest Provision**
(in Dollars)

| Line | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 Beg. True-Up Amount (Schedule 2A, Lines 7 + 7a + 10) | 862,847 | 370,469 | 255,708 | 176,933 | 143,305 | 232,786 | 421,373 | 718,025 | 1,055,704 | 1,061,314 | 978,809 | 984,760 | |
| 2 Ending True-Up Amount Before Interest (Line 1 + Schedule 2A, Lines 5 + 8) | 369,811 | 255,380 | 176,714 | 143,147 | 232,598 | 421,072 | 717,539 | 1,054,925 | 1,060,380 | 977,913 | 983,922 | 1,069,017 | |
| 3 Total of Beginning & Ending True-up (Lines 1 + 2) | 1,232,658 | 625,849 | 432,422 | 320,080 | 375,903 | 653,858 | 1,138,912 | 1,772,950 | 2,116,084 | 2,039,227 | 1,962,731 | 2,053,777 | |
| 4 Average True-Up Amount (Line 3 x 1/2) | 616,329 | 312,925 | 216,211 | 160,040 | 187,952 | 326,929 | 569,456 | 886,475 | 1,058,042 | 1,019,614 | 981,366 | 1,026,889 | |
| 5 Interest Rate (First Day of Reporting Business Month) | 0.012900 | 0.012700 | 0.012500 | 0.011800 | 0.011900 | 0.012100 | 0.010000 | 0.010500 | 0.010600 | 0.010600 | 0.010500 | 0.010000 | |
| 6 Interest Rate (First Day of Subsequent Business Month) | 0.012700 | 0.012500 | 0.011800 | 0.011900 | 0.012100 | 0.010000 | 0.010500 | 0.010600 | 0.010600 | 0.010500 | 0.010000 | 0.010600 | |
| 7 Total of Beginning and Ending Interest Rates (Line 5 + Line 6) | 0.025600 | 0.025200 | 0.024300 | 0.023700 | 0.024000 | 0.022100 | 0.020500 | 0.021100 | 0.021200 | 0.021100 | 0.020500 | 0.020600 | |
| 8 Average Interest Rate (Line 7 x 1/2) | 0.012800 | 0.012600 | 0.012150 | 0.011850 | 0.012000 | 0.011050 | 0.010250 | 0.010550 | 0.010600 | 0.010550 | 0.010250 | 0.010300 | |
| 9 Monthly Average Interest Rate (Line 8 x 1/12) | 0.001067 | 0.001050 | 0.001013 | 0.000988 | 0.001000 | 0.000921 | 0.000854 | 0.000879 | 0.000883 | 0.000879 | 0.000854 | 0.000858 | |
| 10 Interest Provision for the Month (Line 4 x Line 9) | 658 | 328 | 219 | 158 | 188 | 301 | 486 | 779 | 934 | 896 | 838 | 881 | 6,666 |

**Schedule 4A**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

**Variance Report of O & M Activities**
(in Dollars)

| Line | | (1) Actual | (2) Estimated/ Actual | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1 | Description of O & M Activities | | | | |
| | .1 Sulfur | 34,454 | 30,000 | 4,454 | 14.8 % |
| | .2 Air Emission Fees | 753,619 | 759,817 | (6,198) | (0.8) % |
| | .3 Title V | 73,882 | 76,810 | (2,928) | (3.8) % |
| | .4 Asbestos Fees | 2,200 | 4,500 | (2,300) | (51.1) % |
| | .5 Emission Monitoring | 530,723 | 577,779 | (47,056) | (8.1) % |
| | .6 General Water Quality | 225,001 | 379,118 | (154,117) | (40.7) % |
| | .7 Groundwater Contamination Investigation | 864,936 | 895,305 | (30,369) | (3.4) % |
| | .8 State NPDES Administration | 46,993 | 49,500 | (2,507) | (5.1) % |
| | .9 Lead and Copper Rule | 12,580 | 16,500 | (3,920) | (23.8) % |
| | .10 Env Auditing/Assessment | 8,011 | 11,050 | (3,039) | (27.5) % |
| | .11 General Solid & Hazardous Waste | 148,473 | 190,208 | (41,735) | (21.9) % |
| | .12 Above Ground Storage Tanks | 16,045 | 25,000 | (8,955) | (35.8) % |
| | .13 Low Nox | 0 | 0 | 0 | 0.0 % |
| | .14 Ash Pond Diversion Curtains | 0 | 0 | 0 | 0.0 % |
| | .15 Mercury Emissions | 0 | 0 | 0 | 0.0 % |
| | .16 Sodium Injection | 9,153 | 6,000 | 3,153 | 52.6 % |
| | .17 Gulf Coast Ozone Study | 87,277 | 82,559 | 4,718 | 5.7 % |
| | .18 SO2 Allowances | (176,128) | (203,769) | 27,641 | (13.6) % |
| 2 | Total O & M Activities | 2,637,219 | 2,900,377 | (263,158) | (9.1) % |
| 3 | Recoverable Costs Allocated to Energy | 1,312,980 | 1,329,196 | (16,216) | (1.2) % |
| 4 | Recoverable Costs Allocated to Demand | 1,324,239 | 1,571,181 | (246,942) | (15.7) % |

Notes:

Column (1) is the End of Period Totals on Schedule 5A
Column (2) is the approved Estimated/Actual amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Schedule 5A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

**O & M Activities**
(in Dollars)

| Line | | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period 12-Month | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of O & M Activities | | | | | | | | | | | | | | | |
| | .1 Sulfur | - | 3,163 | 26,692 | (10,863) | 1,152 | - | 1,766 | 1,785 | 7,295 | - | 1,717 | 1,747 | 34,454 | | 34,454 |
| | .2 Air Emission Fees | 629,153 | - | - | - | - | 93 | - | - | - | - | 124,373 | - | 753,619 | | 753,619 |
| | .3 Title V | 8,342 | 6,010 | 6,066 | 7,195 | 5,909 | 7,246 | 4,967 | 4,859 | 6,705 | 129,160 | (118,603) | 6,026 | 73,882 | | 73,882 |
| | .4 Asbestos Fees | 500 | 500 | 700 | - | - | - | - | - | - | - | - | 500 | 2,200 | 2,200 | |
| | .5 Emission Monitoring | 32,721 | 78,998 | 24,341 | 17,753 | 71,267 | 84,863 | 34,725 | 15,441 | 66,657 | 47,861 | 17,762 | 38,334 | 530,723 | | 530,723 |
| | .6 General Water Quality | 20,482 | 8,906 | 12,697 | 9,918 | 25,911 | 10,656 | 16,639 | 12,908 | 39,748 | 13,326 | 38,261 | 15,549 | 225,001 | 225,001 | |
| | .7 Groundwater Contamination Investigation | 27,746 | 28,989 | 33,909 | 80,016 | 101,274 | 68,827 | 54,071 | 61,893 | 189,321 | 45,474 | 24,881 | 148,535 | 864,936 | 864,936 | |
| | .8 State NPDES Administration | 34,500 | 2,950 | (2,950) | - | - | - | - | - | 7,500 | - | 4,800 | 193 | 46,993 | 46,993 | |
| | .9 Lead and Copper Rule | 59 | - | - | 118 | 59 | 885 | 118 | 4,613 | 75 | 262 | 260 | 6,131 | 12,580 | 12,580 | |
| | .10 Env Auditing/Assessment | 833 | - | 454 | 439 | 1,377 | 1,947 | 834 | 11 | - | 214 | 1,608 | 294 | 8,011 | 8,011 | |
| | .11 General Solid & Hazardous Waste | 12,424 | 8,314 | 23,605 | 23,027 | 12,090 | 12,042 | 12,159 | 9,915 | 4,820 | 12,726 | 12,455 | 4,896 | 148,473 | 148,473 | |
| | .12 Above Ground Storage Tanks | - | 449 | 616 | 682 | 1,125 | 597 | 8,958 | 100 | - | 16 | 160 | 3,342 | 16,045 | 16,045 | |
| | .13 Low Nox | - | - | - | - | - | - | - | - | - | - | - | - | 0 | | 0 |
| | .14 Ash Pond Diversion Curtains | - | - | - | - | - | - | - | - | - | - | - | - | 0 | | 0 |
| | .15 Mercury Emissions | - | - | - | - | - | - | - | - | - | - | - | - | 0 | | 0 |
| | .16 Sodium Injection | - | - | - | - | - | - | - | - | 4,000 | 599 | 4,554 | - | 9,153 | | 9,153 |
| | .17 Gulf Coast Ozone Study | 571 | 13,051 | 19,615 | 12,099 | 750 | 6,473 | 5,678 | 38 | 305 | 1,069 | 306 | 27,322 | 87,277 | | 87,277 |
| | .18 SO2 Allowances | (4,252) | (4,630) | (4,686) | (4,454) | (4,342) | (26,085) | (25,761) | (25,950) | (26,037) | (26,068) | (26,147) | 2,284 | (176,128) | | (176,128) |
| 2 | Total of O & M Activities | 763,079 | 146,700 | 141,059 | 135,930 | 216,572 | 167,544 | 114,154 | 85,613 | 300,389 | 224,639 | 86,387 | 255,153 | 2,637,219 | 1,324,239 | 1,312,980 |
| 3 | Recoverable Costs Allocated to Energy | 666,535 | 96,592 | 72,028 | 21,730 | 74,736 | 72,589 | 21,376 | (3,827) | 58,925 | 152,620 | 3,962 | 75,714 | 1,312,980 | | |
| 4 | Recoverable Costs Allocated to Demand | 96,544 | 50,108 | 69,031 | 114,200 | 141,836 | 94,955 | 92,778 | 89,440 | 241,464 | 72,019 | 82,425 | 179,439 | 1,324,239 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | | | |
| 6 | Retail Demand Jurisdictional Factor | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | 642,824 | 93,425 | 69,804 | 21,082 | 72,468 | 70,371 | 20,738 | (3,708) | 57,088 | 147,851 | 3,832 | 73,074 | 1,268,849 | | |
| 8 | Jurisdictional Demand Recoverable Costs (B) | 93,167 | 48,355 | 66,616 | 110,205 | 136,874 | 91,633 | 89,533 | 86,311 | 233,017 | 69,500 | 79,542 | 173,162 | 1,277,915 | | |
| 9 | Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8) | 735,991 | 141,780 | 136,420 | 131,287 | 209,342 | 162,004 | 110,271 | 82,603 | 290,105 | 217,351 | 83,374 | 246,236 | 2,546,764 | | |

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

5

**Schedule 6A**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

**Variance Report of Capital Investment Projects - Recoverable Costs**
(in Dollars)

| Line | | (1) Actual | (2) Estimated/ Actual | (3) Variance Amount | (4) Variance Percent | |
|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects | | | | | |
| .1 | Air Quality Assurance Testing | 13,911 | 13,907 | 4 | 0.0 | % |
| .2 | Crist 5, 6 & 7 Precipitator Projects | 2,839,743 | 2,839,745 | (2) | (0.0) | % |
| .3 | Crist 7 Flue Gas Conditioning | 250,317 | 250,318 | (1) | (0.0) | % |
| .4 | Low NOx Burners, Crist 6 & 7 | 1,939,703 | 1,942,098 | (2,395) | (0.1) | % |
| .5 | CEMS - Crist 1, 4-7, 6&7 Upgrade; Scholz 1; Smith 1 & 2; Daniel | 729,795 | 736,664 | (6,869) | (0.9) | % |
| .6 | Sub. Contam. Mobile Groundwater Treat. Sys. | 119,782 | 119,782 | 0 | 0.0 | % |
| .7 | Raw Water Well Flowmeters - Plants Crist & Smith | 34,398 | 34,397 | 1 | 0.0 | % |
| .8 | Crist Cooling Tower Cell | 104,578 | 104,580 | (2) | (0.0) | % |
| .9 | Crist 1-5 Dechlorination | 36,856 | 36,856 | 0 | 0.0 | % |
| .10 | Crist Diesel Fuel Oil Remediation | 5,714 | 5,715 | (1) | (0.0) | % |
| .11 | Crist Bulk Tanker Unload Sec Contain Struc | 12,259 | 12,260 | (1) | (0.0) | % |
| .12 | Crist IWW Sampling System | 7,157 | 7,157 | 0 | 0.0 | % |
| .13 | Smith Sodium Injection System | 14,184 | 14,186 | (2) | (0.0) | % |
| .14 | Smith Stormwater Collection System | 331,457 | 331,457 | 0 | 0.0 | % |
| .15 | Smith Waste Water Treatment Facility | 20,253 | 20,252 | 1 | 0.0 | % |
| .16 | Daniel Ash Management Project | 1,946,762 | 1,946,762 | 0 | 0.0 | % |
| .17 | Smith Shield Water Project | 6,716 | 6,715 | 1 | 0.0 | % |
| .18 | Underground Fuel Tank Replacement | 69,073 | 69,073 | 0 | 0.0 | % |
| .19 | Crist DEP Project | 1,439 | 0 | 1,439 | 100.0 | % |
| .19 | SO2 Allowances | (74,318) | (75,168) | 850 | 1.1 | % |
| 2 | Total Investment Projects - Recoverable Costs | 8,409,779 | 8,416,756 | (6,977) | (0.1) | % |
| 3 | Recoverable Costs Allocated to Energy | 5,922,080 | 5,929,056 | (6,976) | (0.1) | % |
| 4 | Recoverable Costs Allocated to Demand | 2,487,699 | 2,487,700 | (1) | (0.0) | % |

Notes:
Column (1) is the End of Period Totals on Schedule 7A
Column (2) is the approved Estimated/Actual amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI
Column (3) = Column (1) - Column (2)

Schedule 7A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

**Capital Investment Projects - Recoverable Costs**
(in Dollars)

| Line | | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects (A) | | | | | | | | | | | | | | | |
| | .1 Air Quality Assurance Testing | 1,177 | 1,173 | 1,170 | 1,168 | 1,164 | 1,161 | 1,157 | 1,155 | 1,151 | 1,148 | 1,145 | 1,142 | 13,911 | 0 | 13,911 |
| | .2 Crist 5, 6 & 7 Precipitator Projects | 241,540 | 240,649 | 239,760 | 238,870 | 237,979 | 237,090 | 236,200 | 235,309 | 234,422 | 233,531 | 232,640 | 231,753 | 2,839,743 | 0 | 2,839,743 |
| | .3 Crist 7 Flue Gas Conditioning | 21,239 | 21,172 | 21,101 | 21,034 | 20,963 | 20,896 | 20,824 | 20,756 | 20,686 | 20,618 | 20,548 | 20,480 | 250,317 | 0 | 250,317 |
| | .4 Low NOx Burners, Crist 6 & 7 | 163,400 | 162,900 | 162,401 | 161,900 | 161,402 | 161,091 | 160,838 | 160,401 | 159,963 | 159,793 | 159,892 | 165,722 | 1,939,703 | 0 | 1,939,703 |
| | .5 CEMS - Crist 1, 4-7, 6&7 Upgrade; Scholz 1; Smith 1 | 62,718 | 61,941 | 60,972 | 60,883 | 60,780 | 60,674 | 60,562 | 60,458 | 60,348 | 60,237 | 60,128 | 60,094 | 729,795 | 0 | 729,795 |
| | .6 Sub. Contam. Mobile Groundwater Treat. Sys. | 10,087 | 10,070 | 10,050 | 10,030 | 10,010 | 9,992 | 9,972 | 9,953 | 9,935 | 9,915 | 9,892 | 9,876 | 119,782 | 110,568 | 9,214 |
| | .7 Raw Water Well Flowmeters - Plants Crist & Smith | 2,905 | 2,898 | 2,891 | 2,883 | 2,877 | 2,868 | 2,864 | 2,857 | 2,850 | 2,842 | 2,835 | 2,828 | 34,398 | 31,751 | 2,647 |
| | .8 Crist Cooling Tower Cell | 8,878 | 8,848 | 8,820 | 8,789 | 8,760 | 8,730 | 8,700 | 8,670 | 8,639 | 8,612 | 8,580 | 8,552 | 104,578 | 96,533 | 8,045 |
| | .9 Crist 1-5 Dechlorination | 3,122 | 3,113 | 3,104 | 3,094 | 3,085 | 3,077 | 3,066 | 3,058 | 3,048 | 3,039 | 3,030 | 3,020 | 36,856 | 34,022 | 2,834 |
| | .10 Crist Diesel Fuel Oil Remediation | 485 | 483 | 481 | 480 | 478 | 477 | 476 | 474 | 473 | 471 | 469 | 467 | 5,714 | 5,275 | 439 |
| | .11 Crist Bulk Tanker Unload Sec Contain Struc | 1,039 | 1,036 | 1,032 | 1,030 | 1,026 | 1,023 | 1,020 | 1,017 | 1,014 | 1,011 | 1,007 | 1,004 | 12,259 | 11,317 | 942 |
| | .12 Crist IWW Sampling System | 607 | 604 | 604 | 600 | 600 | 596 | 596 | 594 | 592 | 590 | 588 | 586 | 7,157 | 6,607 | 550 |
| | .13 Smith Sodium Injection System | 1,197 | 1,194 | 1,192 | 1,189 | 1,187 | 1,183 | 1,180 | 1,178 | 1,175 | 1,172 | 1,170 | 1,167 | 14,184 | 0 | 14,184 |
| | .14 Smith Stormwater Collection System | 28,018 | 27,946 | 27,874 | 27,802 | 27,730 | 27,658 | 27,585 | 27,513 | 27,441 | 27,369 | 27,297 | 27,224 | 331,457 | 305,960 | 25,497 |
| | .15 Smith Waste Water Treatment Facility | 1,713 | 1,708 | 1,704 | 1,699 | 1,695 | 1,690 | 1,686 | 1,681 | 1,676 | 1,672 | 1,667 | 1,662 | 20,253 | 18,695 | 1,558 |
| | .16 Daniel Ash Management Project | 164,343 | 163,959 | 163,575 | 163,191 | 162,807 | 162,422 | 162,038 | 161,653 | 161,270 | 160,885 | 160,502 | 160,117 | 1,946,762 | 1,797,011 | 149,751 |
| | .17 Smith Shield Water Project | 566 | 565 | 564 | 563 | 562 | 561 | 559 | 558 | 557 | 555 | 554 | 552 | 6,716 | 6,200 | 516 |
| | .18 Underground Fuel Tank Replacement | 6,012 | 5,964 | 5,918 | 5,873 | 5,825 | 5,779 | 5,734 | 5,686 | 5,639 | 5,594 | 5,548 | 5,501 | 69,073 | 63,760 | 5,313 |
| | .19 Crist DEP Project | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,439 | 1,439 | 0 | 1,439 |
| | .20 SO2 Allowances | (5,804) | (5,763) | (5,718) | (5,676) | (5,634) | (6,511) | (7,123) | (6,807) | (6,656) | (6,410) | (6,164) | (6,052) | (74,318) | 0 | (74,318) |
| 2 | Total Investment Projects - Recoverable Costs | 713,242 | 710,460 | 707,495 | 705,402 | 703,296 | 700,457 | 697,934 | 696,164 | 694,223 | 692,644 | 691,328 | 697,134 | 8,409,779 | 2,487,699 | 5,922,080 |
| 3 | Recoverable Costs Allocated to Energy | 502,989 | 500,742 | 498,308 | 496,755 | 495,183 | 492,885 | 490,892 | 489,656 | 488,253 | 487,209 | 486,433 | 492,775 | 5,922,080 | | |
| 4 | Recoverable Costs Allocated to Demand | 210,253 | 209,718 | 209,187 | 208,647 | 208,113 | 207,572 | 207,042 | 206,508 | 205,970 | 205,435 | 204,895 | 204,359 | 2,487,699 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | | | |
| 6 | Retail Demand Jurisdictional Factor | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | 485,096 | 484,324 | 482,918 | 481,951 | 480,153 | 477,822 | 476,234 | 474,444 | 473,033 | 471,983 | 470,484 | 475,590 | 5,734,032 | | |
| 8 | Jurisdictional Demand Recoverable Costs (C) | 202,898 | 202,382 | 201,869 | 201,348 | 200,833 | 200,311 | 199,799 | 199,284 | 198,765 | 198,249 | 197,728 | 197,210 | 2,400,676 | | |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | 687,994 | 686,706 | 684,787 | 683,299 | 680,986 | 678,133 | 676,033 | 673,728 | 671,798 | 670,232 | 668,212 | 672,800 | 8,134,708 | | |

Notes:

(A) Reference Pages 1-18 of Schedule 8A Line 9 and Page 19 of Schedule 8A Line 6
(B) Line 3 x Line 5 x Line loss multiplier

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 61,641 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 267,056 | 267,056 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | |
| 3 | Less: Accumulated Depreciation (C) | (239,115) | (239,448) | (239,780) | (240,113) | (240,446) | (240,778) | (241,111) | (241,443) | (241,776) | (242,109) | (242,441) | (242,774) | (243,107) | |
| 4 | CWIP - Non Interest Bearing | 61,641 | 61,641 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 89,582 | 89,249 | 88,917 | 88,584 | 88,251 | 87,919 | 87,586 | 87,254 | 86,921 | 86,588 | 86,256 | 85,923 | 85,590 | |
| 6 | Average Net Investment | | 89,416 | 89,083 | 88,751 | 88,418 | 88,085 | 87,753 | 87,420 | 87,087 | 86,755 | 86,422 | 86,089 | 85,757 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 657 | 654 | 652 | 650 | 647 | 645 | 642 | 640 | 637 | 635 | 632 | 630 | 7,721 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 187 | 186 | 185 | 185 | 184 | 183 | 182 | 182 | 181 | 180 | 180 | 179 | 2,194 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b Amortization (F) | | 333 | 333 | 333 | 333 | 333 | 333 | 333 | 333 | 333 | 333 | 333 | 333 | 3,996 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 1,177 | 1,173 | 1,170 | 1,168 | 1,164 | 1,161 | 1,157 | 1,155 | 1,151 | 1,148 | 1,145 | 1,142 | 13,911 |
| | a Recoverable Costs Allocated to Energy | | 1,177 | 1,173 | 1,170 | 1,168 | 1,164 | 1,161 | 1,157 | 1,155 | 1,151 | 1,148 | 1,145 | 1,142 | 13,911 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 1,135 | 1,135 | 1,134 | 1,133 | 1,129 | 1,126 | 1,122 | 1,119 | 1,115 | 1,112 | 1,107 | 1,102 | 13,469 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 1,135 | 1,135 | 1,134 | 1,133 | 1,129 | 1,126 | 1,122 | 1,119 | 1,115 | 1,112 | 1,107 | 1,102 | 13,469 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) 7 year amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1119, 1216, 1243
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | |
| 3 | Less: Accumulated Depreciation (C) | (8,788,768) | (8,883,092) | (8,977,414) | (9,071,737) | (9,166,060) | (9,260,382) | (9,354,705) | (9,449,028) | (9,543,350) | (9,637,674) | (9,731,997) | (9,826,319) | (9,920,644) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 15,652,057 | 15,557,733 | 15,463,411 | 15,369,088 | 15,274,765 | 15,180,443 | 15,086,120 | 14,991,797 | 14,897,475 | 14,803,151 | 14,708,828 | 14,614,506 | 14,520,181 | |
| 6 | Average Net Investment | | 15,604,895 | 15,510,572 | 15,416,250 | 15,321,927 | 15,227,604 | 15,133,282 | 15,038,959 | 14,944,636 | 14,850,313 | 14,755,990 | 14,661,667 | 14,567,344 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 114,649 | 113,956 | 113,263 | 112,570 | 111,877 | 111,184 | 110,491 | 109,798 | 109,105 | 108,412 | 107,719 | 107,026 | 1,330,050 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 32,567 | 32,371 | 32,174 | 31,977 | 31,780 | 31,583 | 31,386 | 31,189 | 30,993 | 30,796 | 30,599 | 30,402 | 377,817 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 79,433 | 79,432 | 79,433 | 79,433 | 79,432 | 79,432 | 79,433 | 79,432 | 79,433 | 79,433 | 79,432 | 79,434 | 953,192 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 14,891 | 14,890 | 14,890 | 14,890 | 14,890 | 14,891 | 14,890 | 14,890 | 14,891 | 14,890 | 14,890 | 14,891 | 178,684 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 241,540 | 240,649 | 239,760 | 238,870 | 237,979 | 237,090 | 236,200 | 235,309 | 234,422 | 233,531 | 232,640 | 231,753 | 2,839,743 |
| | a Recoverable Costs Allocated to Energy | | 241,540 | 240,649 | 239,760 | 238,870 | 237,979 | 237,090 | 236,200 | 235,309 | 234,422 | 233,531 | 232,640 | 231,753 | 2,839,743 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 232,948 | 232,759 | 232,355 | 231,751 | 230,756 | 229,844 | 229,147 | 227,999 | 227,114 | 226,233 | 225,012 | 223,671 | 2,749,589 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 232,948 | 232,759 | 232,355 | 231,751 | 230,756 | 229,844 | 229,147 | 227,999 | 227,114 | 226,233 | 225,012 | 223,671 | 2,749,589 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | |
| 3 | Less: Accumulated Depreciation (C) | (702,014) | (709,352) | (716,692) | (724,030) | (731,370) | (738,708) | (746,048) | (753,386) | (760,725) | (768,063) | (775,403) | (782,742) | (790,082) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 1,477,231 | 1,469,893 | 1,462,553 | 1,455,215 | 1,447,875 | 1,440,537 | 1,433,197 | 1,425,859 | 1,418,520 | 1,411,182 | 1,403,842 | 1,396,503 | 1,389,163 | |
| 6 | Average Net Investment | | 1,473,562 | 1,466,223 | 1,458,884 | 1,451,545 | 1,444,206 | 1,436,867 | 1,429,528 | 1,422,190 | 1,414,851 | 1,407,512 | 1,400,173 | 1,392,833 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 10,826 | 10,772 | 10,718 | 10,665 | 10,611 | 10,557 | 10,503 | 10,449 | 10,395 | 10,341 | 10,287 | 10,233 | 126,357 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 3,075 | 3,060 | 3,045 | 3,029 | 3,014 | 2,999 | 2,983 | 2,968 | 2,953 | 2,937 | 2,922 | 2,907 | 35,892 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 7,082 | 7,083 | 7,082 | 7,083 | 7,082 | 7,083 | 7,082 | 7,082 | 7,082 | 7,083 | 7,083 | 7,083 | 84,990 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 256 | 257 | 256 | 257 | 256 | 257 | 256 | 257 | 256 | 257 | 256 | 257 | 3,078 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 21,239 | 21,172 | 21,101 | 21,034 | 20,963 | 20,896 | 20,824 | 20,756 | 20,686 | 20,618 | 20,548 | 20,480 | 250,317 |
| | a Recoverable Costs Allocated to Energy | | 21,239 | 21,172 | 21,101 | 21,034 | 20,963 | 20,896 | 20,824 | 20,756 | 20,686 | 20,618 | 20,548 | 20,480 | 250,317 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 20,483 | 20,478 | 20,449 | 20,407 | 20,327 | 20,257 | 20,202 | 20,111 | 20,041 | 19,974 | 19,874 | 19,766 | 242,369 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 20,483 | 20,478 | 20,449 | 20,407 | 20,327 | 20,257 | 20,202 | 20,111 | 20,041 | 19,974 | 19,874 | 19,766 | 242,369 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236 and 1242
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 40,142 | 12,141 | 1,172 | 12,056 | 57,689 | 68,967 | 1,272,971 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 16,296,359 | 16,296,359 | 16,296,359 | 16,296,359 | 16,296,359 | 16,296,359 | 16,296,359 | 16,296,359 | 16,296,359 | 16,296,359 | 16,296,359 | 16,296,359 | 16,296,359 | |
| 3 | Less: Accumulated Depreciation (C) | (4,563,638) | (4,616,601) | (4,669,564) | (4,722,527) | (4,775,490) | (4,828,454) | (4,881,417) | (4,934,380) | (4,987,343) | (5,040,305) | (5,093,268) | (5,146,232) | (5,199,196) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 40,142 | 52,283 | 53,455 | 65,511 | 123,200 | 192,167 | 1,465,138 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 11,732,721 | 11,679,758 | 11,626,795 | 11,573,832 | 11,520,869 | 11,467,905 | 11,455,084 | 11,414,262 | 11,362,471 | 11,321,565 | 11,326,291 | 11,342,294 | 12,562,301 | |
| 6 | Average Net Investment | | 11,706,240 | 11,653,277 | 11,600,314 | 11,547,351 | 11,494,387 | 11,461,495 | 11,434,673 | 11,388,367 | 11,342,018 | 11,323,928 | 11,334,293 | 11,952,298 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 86,006 | 85,617 | 85,228 | 84,838 | 84,449 | 84,208 | 84,011 | 83,670 | 83,330 | 83,197 | 83,273 | 87,814 | 1,015,641 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 24,431 | 24,320 | 24,210 | 24,099 | 23,989 | 23,920 | 23,864 | 23,768 | 23,671 | 23,633 | 23,655 | 24,944 | 288,504 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 52,963 | 52,963 | 52,963 | 52,963 | 52,964 | 52,963 | 52,963 | 52,963 | 52,962 | 52,963 | 52,964 | 52,964 | 635,558 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 163,400 | 162,900 | 162,401 | 161,900 | 161,402 | 161,091 | 160,838 | 160,401 | 159,963 | 159,793 | 159,892 | 165,722 | 1,939,703 |
| | a Recoverable Costs Allocated to Energy | | 163,400 | 162,900 | 162,401 | 161,900 | 161,402 | 161,091 | 160,838 | 160,401 | 159,963 | 159,793 | 159,892 | 165,722 | 1,939,703 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 157,587 | 157,559 | 157,385 | 157,075 | 156,503 | 156,168 | 156,035 | 155,418 | 154,977 | 154,799 | 154,649 | 159,943 | 1,878,098 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 157,587 | 157,559 | 157,385 | 157,075 | 156,503 | 156,168 | 156,035 | 155,418 | 154,977 | 154,799 | 154,649 | 159,943 | 1,878,098 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Crist 1, 4-7, 6&7 Upgrade; Scholz 1; Smith 1 & 2; Daniel
P.E.s 1154, 1164, 1240, 1245, 1286, 1289, 1290, 1311, 1316, 1323, 1440, 1441, 1442, 1454, 1459, 1460 & 1558
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | (594) | 2,825 | 373 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11,387 | |
| | b Clearings to Plant | | 128,310 | (594) | 0 | 3,198 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11,387 | |
| | c Retirements | | 0 | 533,256 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 729 | 0 | (373) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 4,329,296 | 4,457,606 | 3,923,756 | 3,923,756 | 3,926,954 | 3,926,954 | 3,926,954 | 3,926,954 | 3,926,954 | 3,926,954 | 3,926,954 | 3,926,954 | 3,938,341 | |
| 3 | Less: Accumulated Depreciation (C) | 670,339 | 657,327 | 1,178,959 | 1,167,476 | 1,155,614 | 1,144,119 | 1,132,622 | 1,121,128 | 1,109,630 | 1,098,134 | 1,086,640 | 1,075,147 | 1,063,633 | |
| 4 | CWIP - Non Interest Bearing | 128,310 | 0 | 0 | 2,825 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 5,127,945 | 5,114,933 | 5,102,715 | 5,094,057 | 5,082,568 | 5,071,073 | 5,059,576 | 5,048,082 | 5,036,584 | 5,025,088 | 5,013,594 | 5,002,101 | 5,001,974 | |
| 6 | Average Net Investment | | 5,121,439 | 5,108,824 | 5,098,386 | 5,088,313 | 5,076,821 | 5,065,325 | 5,053,829 | 5,042,333 | 5,030,836 | 5,019,341 | 5,007,848 | 5,002,038 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 37,627 | 37,535 | 37,458 | 37,384 | 37,299 | 37,215 | 37,130 | 37,046 | 36,962 | 36,877 | 36,793 | 36,750 | 446,076 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 10,688 | 10,662 | 10,640 | 10,619 | 10,595 | 10,571 | 10,547 | 10,523 | 10,499 | 10,475 | 10,451 | 10,439 | 126,709 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 13,012 | 12,353 | 11,483 | 11,489 | 11,495 | 11,497 | 11,494 | 11,498 | 11,496 | 11,494 | 11,493 | 11,514 | 140,318 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 | 16,692 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 62,718 | 61,941 | 60,972 | 60,883 | 60,780 | 60,674 | 60,562 | 60,458 | 60,348 | 60,237 | 60,128 | 60,094 | 729,795 |
| | a Recoverable Costs Allocated to Energy | | 62,718 | 61,941 | 60,972 | 60,883 | 60,780 | 60,674 | 60,562 | 60,458 | 60,348 | 60,237 | 60,128 | 60,094 | 729,795 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 60,487 | 59,910 | 59,089 | 59,069 | 58,935 | 58,820 | 58,754 | 58,580 | 58,467 | 58,355 | 58,157 | 57,998 | 706,621 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 60,487 | 59,910 | 59,089 | 59,069 | 58,935 | 58,820 | 58,754 | 58,580 | 58,467 | 58,355 | 58,157 | 57,998 | 706,621 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $2,590,992; Scholz $486,599; Smith $685,842; and Daniel $565,863. Ending Balances: Crist $2,200,037; Scholz $486,599; Smith $685,842; and Daniel $565,863
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) Crist: 3.9%, Smith 3.3%, Scholz 2.9%, Daniel 2.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Sub. Contam. Mobile Groundwater Treat. Sys.
P.E. 1007, 3400, & 3412
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | |
| 3 | Less: Accumulated Depreciation (C) | (76,138) | (78,185) | (80,233) | (82,281) | (84,328) | (86,375) | (88,423) | (90,470) | (92,517) | (94,565) | (96,613) | (98,659) | (100,707) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 853,256 | 851,209 | 849,161 | 847,113 | 845,066 | 843,019 | 840,971 | 838,924 | 836,877 | 834,829 | 832,781 | 830,735 | 828,687 | |
| 6 | Average Net Investment | | 852,233 | 850,186 | 848,137 | 846,090 | 844,043 | 841,996 | 839,948 | 837,901 | 835,854 | 833,806 | 831,759 | 829,712 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 6,261 | 6,246 | 6,231 | 6,216 | 6,201 | 6,186 | 6,171 | 6,156 | 6,141 | 6,126 | 6,111 | 6,096 | 74,142 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 1,779 | 1,774 | 1,770 | 1,766 | 1,762 | 1,757 | 1,753 | 1,749 | 1,744 | 1,740 | 1,736 | 1,732 | 21,062 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 1,912 | 1,913 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,913 | 1,911 | 1,912 | 22,945 |
| | b Amortization (F) | | 135 | 135 | 136 | 135 | 135 | 136 | 135 | 135 | 136 | 135 | 135 | 136 | 1,624 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 10,087 | 10,070 | 10,050 | 10,030 | 10,010 | 9,992 | 9,972 | 9,953 | 9,935 | 9,915 | 9,892 | 9,876 | 119,782 |
| | a Recoverable Costs Allocated to Energy | | 776 | 775 | 773 | 771 | 770 | 769 | 767 | 765 | 764 | 763 | 761 | 760 | 9,214 |
| | b Recoverable Costs Allocated to Demand | | 9,311 | 9,295 | 9,277 | 9,259 | 9,240 | 9,223 | 9,205 | 9,188 | 9,171 | 9,152 | 9,131 | 9,116 | 110,568 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 748 | 750 | 749 | 748 | 747 | 745 | 744 | 741 | 740 | 739 | 736 | 733 | 8,920 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 8,985 | 8,970 | 8,952 | 8,935 | 8,917 | 8,900 | 8,883 | 8,867 | 8,850 | 8,832 | 8,812 | 8,797 | 106,700 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 9,733 | 9,720 | 9,701 | 9,683 | 9,664 | 9,645 | 9,627 | 9,608 | 9,590 | 9,571 | 9,548 | 9,530 | 115,620 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and ending balance of depreciable property $918,024; Beginning and Ending Balance of amortizable property $11,370
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) Part of PE 1007 depreciable at 2.5% annually. PEs 3400 and 3412 depreciable at 2.5% annually
(F) 7 year amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith
P.E. 1155 & 1606
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | |
| 3 | Less: Accumulated Depreciation (C) | (13,373) | (14,116) | (14,859) | (15,602) | (16,345) | (17,088) | (17,830) | (18,573) | (19,317) | (20,061) | (20,804) | (21,547) | (22,290) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 229,570 | 228,827 | 228,084 | 227,341 | 226,598 | 225,855 | 225,113 | 224,370 | 223,626 | 222,882 | 222,139 | 221,396 | 220,653 | |
| 6 | Average Net Investment | | 229,199 | 228,456 | 227,713 | 226,970 | 226,227 | 225,485 | 224,742 | 223,998 | 223,254 | 222,511 | 221,768 | 221,025 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 1,684 | 1,678 | 1,673 | 1,668 | 1,662 | 1,657 | 1,651 | 1,646 | 1,640 | 1,635 | 1,629 | 1,624 | 19,847 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 478 | 477 | 475 | 474 | 472 | 471 | 469 | 467 | 466 | 464 | 463 | 461 | 5,637 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 743 | 743 | 743 | 743 | 743 | 742 | 743 | 744 | 744 | 743 | 743 | 743 | 8,917 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 2,905 | 2,898 | 2,891 | 2,883 | 2,877 | 2,868 | 2,864 | 2,857 | 2,850 | 2,842 | 2,835 | 2,828 | 34,401 |
| | a Recoverable Costs Allocated to Energy | | 224 | 223 | 222 | 222 | 221 | 221 | 221 | 219 | 219 | 219 | 218 | 218 | 2,647 |
| | b Recoverable Costs Allocated to Demand | | 2,681 | 2,675 | 2,669 | 2,661 | 2,656 | 2,647 | 2,643 | 2,638 | 2,631 | 2,623 | 2,617 | 2,610 | 31,751 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 216 | 216 | 215 | 215 | 214 | 214 | 214 | 212 | 212 | 212 | 211 | 210 | 2,561 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,587 | 2,581 | 2,576 | 2,568 | 2,563 | 2,554 | 2,551 | 2,546 | 2,539 | 2,531 | 2,525 | 2,519 | 30,640 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 2,803 | 2,797 | 2,791 | 2,783 | 2,777 | 2,768 | 2,765 | 2,758 | 2,751 | 2,743 | 2,736 | 2,729 | 33,201 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balance for Crist: $149,920; Beginning and Ending Balance for Smith $93,023
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) Crist: 3.9% Smith 3.3% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | |
| 3 | Less: Accumulated Depreciation (C) | (297,961) | (301,111) | (304,262) | (307,414) | (310,565) | (313,716) | (316,867) | (320,017) | (323,168) | (326,318) | (329,470) | (332,620) | (335,771) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 608,698 | 605,548 | 602,397 | 599,245 | 596,094 | 592,943 | 589,792 | 586,642 | 583,491 | 580,341 | 577,189 | 574,039 | 570,888 | |
| 6 | Average Net Investment | | 607,123 | 603,973 | 600,821 | 597,670 | 594,519 | 591,368 | 588,217 | 585,067 | 581,916 | 578,765 | 575,614 | 572,464 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 4,461 | 4,437 | 4,414 | 4,391 | 4,368 | 4,345 | 4,322 | 4,298 | 4,275 | 4,252 | 4,229 | 4,206 | 51,998 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 1,267 | 1,260 | 1,254 | 1,247 | 1,241 | 1,234 | 1,228 | 1,221 | 1,214 | 1,208 | 1,201 | 1,195 | 14,770 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 2,946 | 2,947 | 2,947 | 2,947 | 2,947 | 2,946 | 2,946 | 2,946 | 2,946 | 2,947 | 2,946 | 2,947 | 35,358 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 204 | 204 | 205 | 204 | 204 | 205 | 204 | 205 | 204 | 205 | 204 | 204 | 2,452 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 8,878 | 8,848 | 8,820 | 8,789 | 8,760 | 8,730 | 8,700 | 8,670 | 8,639 | 8,612 | 8,580 | 8,552 | 104,578 |
| | a Recoverable Costs Allocated to Energy | | 683 | 681 | 678 | 676 | 674 | 672 | 669 | 667 | 665 | 662 | 660 | 658 | 8,045 |
| | b Recoverable Costs Allocated to Demand | | 8,195 | 8,167 | 8,142 | 8,113 | 8,086 | 8,058 | 8,031 | 8,003 | 7,974 | 7,950 | 7,920 | 7,894 | 96,533 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 659 | 659 | 657 | 656 | 654 | 651 | 649 | 646 | 644 | 641 | 638 | 635 | 7,789 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 7,908 | 7,881 | 7,857 | 7,829 | 7,803 | 7,776 | 7,750 | 7,723 | 7,695 | 7,672 | 7,643 | 7,618 | 93,155 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 8,567 | 8,540 | 8,514 | 8,485 | 8,457 | 8,427 | 8,399 | 8,369 | 8,339 | 8,313 | 8,281 | 8,253 | 100,944 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 1-5 Dechlorination
P.E. 1248
(in Dollars)

| Line | Description | Beginning of Period Amoun | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | |
| 3 | Less: Accumulated Depreciation (C) | (78,990) | (79,982) | (80,974) | (81,966) | (82,958) | (83,950) | (84,943) | (85,935) | (86,928) | (87,920) | (88,912) | (89,905) | (90,897) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 226,333 | 225,341 | 224,349 | 223,357 | 222,365 | 221,373 | 220,380 | 219,388 | 218,395 | 217,403 | 216,411 | 215,418 | 214,426 | |
| 6 | Average Net Investment | | 225,837 | 224,845 | 223,853 | 222,861 | 221,869 | 220,877 | 219,884 | 218,892 | 217,899 | 216,907 | 215,915 | 214,922 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 1,659 | 1,652 | 1,645 | 1,637 | 1,630 | 1,623 | 1,615 | 1,608 | 1,601 | 1,594 | 1,586 | 1,579 | 19,429 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 471 | 469 | 467 | 465 | 463 | 461 | 459 | 457 | 455 | 453 | 451 | 449 | 5,520 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 992 | 992 | 992 | 992 | 992 | 993 | 992 | 993 | 992 | 992 | 993 | 992 | 11,907 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 3,122 | 3,113 | 3,104 | 3,094 | 3,085 | 3,077 | 3,066 | 3,058 | 3,048 | 3,039 | 3,030 | 3,020 | 36,856 |
| | a Recoverable Costs Allocated to Energy | | 240 | 239 | 239 | 238 | 237 | 237 | 236 | 235 | 234 | 234 | 233 | 232 | 2,834 |
| | b Recoverable Costs Allocated to Demand | | 2,882 | 2,874 | 2,865 | 2,856 | 2,848 | 2,840 | 2,830 | 2,823 | 2,814 | 2,805 | 2,797 | 2,788 | 34,022 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 231 | 231 | 232 | 231 | 230 | 230 | 229 | 228 | 227 | 227 | 225 | 224 | 2,745 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,781 | 2,773 | 2,765 | 2,756 | 2,748 | 2,741 | 2,731 | 2,724 | 2,716 | 2,707 | 2,699 | 2,690 | 32,831 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 3,012 | 3,004 | 2,997 | 2,987 | 2,978 | 2,971 | 2,960 | 2,952 | 2,943 | 2,934 | 2,924 | 2,914 | 35,576 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | |
| 3 | Less: Accumulated Depreciation (C) | (13,066) | (13,222) | (13,378) | (13,534) | (13,690) | (13,846) | (14,002) | (14,158) | (14,314) | (14,470) | (14,626) | (14,782) | (14,937) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 34,889 | 34,733 | 34,577 | 34,421 | 34,265 | 34,109 | 33,953 | 33,797 | 33,641 | 33,485 | 33,329 | 33,173 | 33,018 | |
| 6 | Average Net Investment | | 34,811 | 34,655 | 34,499 | 34,343 | 34,187 | 34,031 | 33,875 | 33,719 | 33,563 | 33,407 | 33,251 | 33,096 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 256 | 255 | 253 | 252 | 251 | 250 | 249 | 248 | 247 | 245 | 244 | 243 | 2,993 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 73 | 72 | 72 | 72 | 71 | 71 | 71 | 70 | 70 | 70 | 69 | 69 | 850 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 155 | 1,871 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 485 | 483 | 481 | 480 | 478 | 477 | 476 | 474 | 473 | 471 | 469 | 467 | 5,714 |
| | a Recoverable Costs Allocated to Energy | | 37 | 37 | 37 | 37 | 37 | 37 | 37 | 36 | 36 | 36 | 36 | 36 | 439 |
| | b Recoverable Costs Allocated to Demand | | 448 | 446 | 444 | 443 | 441 | 440 | 439 | 438 | 437 | 435 | 433 | 431 | 5,275 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 35 | 35 | 35 | 35 | 35 | 427 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 432 | 430 | 428 | 428 | 426 | 425 | 424 | 423 | 422 | 420 | 418 | 416 | 5,092 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 468 | 466 | 464 | 464 | 462 | 461 | 460 | 458 | 457 | 455 | 453 | 451 | 5,519 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unload Sec Contain Struc
P.E. 1271
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | |
| 3 | Less: Accumulated Depreciation (C) | (26,193) | (26,523) | (26,853) | (27,183) | (27,513) | (27,843) | (28,173) | (28,503) | (28,833) | (29,163) | (29,493) | (29,822) | (30,152) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 75,302 | 74,972 | 74,642 | 74,312 | 73,982 | 73,652 | 73,322 | 72,992 | 72,662 | 72,332 | 72,002 | 71,673 | 71,343 | |
| 6 | Average Net Investment | | 75,137 | 74,807 | 74,477 | 74,147 | 73,817 | 73,487 | 73,157 | 72,827 | 72,497 | 72,167 | 71,838 | 71,508 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 552 | 550 | 547 | 545 | 542 | 540 | 537 | 535 | 533 | 530 | 528 | 525 | 6,464 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 157 | 156 | 155 | 155 | 154 | 153 | 153 | 152 | 151 | 151 | 150 | 149 | 1,836 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 329 | 330 | 3,959 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 1,039 | 1,036 | 1,032 | 1,030 | 1,026 | 1,023 | 1,020 | 1,017 | 1,014 | 1,011 | 1,007 | 1,004 | 12,259 |
| | a Recoverable Costs Allocated to Energy | | 80 | 80 | 79 | 79 | 79 | 79 | 78 | 78 | 78 | 78 | 77 | 77 | 942 |
| | b Recoverable Costs Allocated to Demand | | 959 | 956 | 953 | 951 | 947 | 944 | 942 | 939 | 936 | 933 | 930 | 927 | 11,317 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 77 | 77 | 77 | 77 | 77 | 77 | 76 | 76 | 76 | 76 | 74 | 74 | 914 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 925 | 923 | 920 | 918 | 914 | 911 | 909 | 906 | 903 | 900 | 897 | 895 | 10,921 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 1,002 | 1,000 | 997 | 995 | 991 | 988 | 985 | 982 | 979 | 976 | 971 | 969 | 11,835 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | |
| 3 | Less: Accumulated Depreciation (C) | (15,684) | (15,878) | (16,071) | (16,265) | (16,458) | (16,652) | (16,845) | (17,039) | (17,232) | (17,426) | (17,619) | (17,813) | (18,006) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 43,859 | 43,665 | 43,472 | 43,278 | 43,085 | 42,891 | 42,698 | 42,504 | 42,311 | 42,117 | 41,924 | 41,730 | 41,537 | |
| 6 | Average Net Investment | | 43,762 | 43,569 | 43,375 | 43,182 | 42,988 | 42,795 | 42,601 | 42,408 | 42,214 | 42,021 | 41,827 | 41,634 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 322 | 320 | 319 | 317 | 316 | 314 | 313 | 312 | 310 | 309 | 307 | 306 | 3,765 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 91 | 91 | 91 | 90 | 90 | 89 | 89 | 89 | 88 | 88 | 87 | 87 | 1,070 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 194 | 193 | 194 | 193 | 194 | 193 | 194 | 193 | 194 | 193 | 194 | 193 | 2,322 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 607 | 604 | 604 | 600 | 600 | 596 | 596 | 594 | 592 | 590 | 588 | 586 | 7,157 |
| | a Recoverable Costs Allocated to Energy | | 47 | 46 | 46 | 46 | 46 | 46 | 46 | 46 | 46 | 45 | 45 | 45 | 550 |
| | b Recoverable Costs Allocated to Demand | | 560 | 558 | 558 | 554 | 554 | 550 | 550 | 548 | 546 | 545 | 543 | 541 | 6,607 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 45 | 44 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 44 | 44 | 43 | 535 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 540 | 538 | 538 | 535 | 535 | 531 | 531 | 529 | 527 | 526 | 524 | 522 | 6,376 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 585 | 582 | 583 | 580 | 580 | 576 | 576 | 574 | 572 | 570 | 568 | 565 | 6,911 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Sodium Injection System
P.E. 1413
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | |
| 3 | Less: Accumulated Depreciation (C) | (10,474) | (10,767) | (11,060) | (11,353) | (11,646) | (11,939) | (12,231) | (12,524) | (12,817) | (13,110) | (13,402) | (13,695) | (13,988) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 96,023 | 95,730 | 95,437 | 95,144 | 94,851 | 94,558 | 94,266 | 93,973 | 93,680 | 93,387 | 93,095 | 92,802 | 92,509 | |
| 6 | Average Net Investment | | 95,877 | 95,584 | 95,291 | 94,998 | 94,705 | 94,412 | 94,120 | 93,827 | 93,534 | 93,241 | 92,949 | 92,656 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 704 | 702 | 700 | 698 | 696 | 694 | 691 | 689 | 687 | 685 | 683 | 681 | 8,310 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 200 | 199 | 199 | 198 | 198 | 197 | 196 | 196 | 195 | 195 | 194 | 193 | 2,360 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 293 | 293 | 293 | 293 | 293 | 292 | 293 | 293 | 293 | 292 | 293 | 293 | 3,514 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 1,197 | 1,194 | 1,192 | 1,189 | 1,187 | 1,183 | 1,180 | 1,178 | 1,175 | 1,172 | 1,170 | 1,167 | 14,184 |
| | a Recoverable Costs Allocated to Energy | | 1,197 | 1,194 | 1,192 | 1,189 | 1,187 | 1,183 | 1,180 | 1,178 | 1,175 | 1,172 | 1,170 | 1,167 | 14,184 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 1,154 | 1,155 | 1,155 | 1,154 | 1,151 | 1,147 | 1,145 | 1,141 | 1,138 | 1,135 | 1,132 | 1,126 | 13,733 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 1,154 | 1,155 | 1,155 | 1,154 | 1,151 | 1,147 | 1,145 | 1,141 | 1,138 | 1,135 | 1,132 | 1,126 | 13,733 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | |
| 3 | Less: Accumulated Depreciation (C) | (619,962) | (627,614) | (635,266) | (642,918) | (650,570) | (658,222) | (665,874) | (673,526) | (681,178) | (688,830) | (696,482) | (704,134) | (711,786) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 2,162,638 | 2,154,986 | 2,147,334 | 2,139,682 | 2,132,030 | 2,124,378 | 2,116,726 | 2,109,074 | 2,101,422 | 2,093,770 | 2,086,118 | 2,078,466 | 2,070,814 | |
| 6 | Average Net Investment | | 2,158,812 | 2,151,160 | 2,143,508 | 2,135,856 | 2,128,204 | 2,120,552 | 2,112,900 | 2,105,248 | 2,097,596 | 2,089,944 | 2,082,292 | 2,074,640 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 15,861 | 15,805 | 15,748 | 15,692 | 15,636 | 15,580 | 15,523 | 15,467 | 15,411 | 15,355 | 15,299 | 15,242 | 186,619 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 4,505 | 4,489 | 4,474 | 4,458 | 4,442 | 4,426 | 4,410 | 4,394 | 4,378 | 4,362 | 4,346 | 4,330 | 53,014 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 91,824 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 28,018 | 27,946 | 27,874 | 27,802 | 27,730 | 27,658 | 27,585 | 27,513 | 27,441 | 27,369 | 27,297 | 27,224 | 331,457 |
| | a Recoverable Costs Allocated to Energy | | 2,155 | 2,150 | 2,144 | 2,139 | 2,133 | 2,128 | 2,122 | 2,116 | 2,111 | 2,105 | 2,100 | 2,094 | 25,497 |
| | b Recoverable Costs Allocated to Demand | | 25,863 | 25,796 | 25,730 | 25,663 | 25,597 | 25,530 | 25,463 | 25,397 | 25,330 | 25,264 | 25,197 | 25,130 | 305,960 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 2,078 | 2,080 | 2,078 | 2,075 | 2,068 | 2,063 | 2,059 | 2,050 | 2,045 | 2,039 | 2,031 | 2,021 | 24,687 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 24,958 | 24,894 | 24,830 | 24,765 | 24,702 | 24,637 | 24,572 | 24,509 | 24,444 | 24,380 | 24,316 | 24,251 | 295,258 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 27,036 | 26,974 | 26,908 | 26,840 | 26,770 | 26,700 | 26,631 | 26,559 | 26,489 | 26,419 | 26,347 | 26,272 | 319,945 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E. 1466
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | |
| 3 | Less: Accumulated Depreciation (C) | (44,462) | (44,944) | (45,426) | (45,908) | (46,390) | (46,872) | (47,354) | (47,836) | (48,318) | (48,800) | (49,282) | (49,764) | (50,245) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 130,738 | 130,256 | 129,774 | 129,292 | 128,810 | 128,328 | 127,846 | 127,364 | 126,882 | 126,400 | 125,918 | 125,436 | 124,955 | |
| 6 | Average Net Investment | | 130,497 | 130,015 | 129,533 | 129,051 | 128,569 | 128,087 | 127,605 | 127,123 | 126,641 | 126,159 | 125,677 | 125,196 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 959 | 955 | 952 | 948 | 945 | 941 | 938 | 934 | 930 | 927 | 923 | 920 | 11,272 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 272 | 271 | 270 | 269 | 268 | 267 | 266 | 265 | 264 | 263 | 262 | 261 | 3,198 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 482 | 482 | 482 | 482 | 482 | 482 | 482 | 482 | 482 | 482 | 482 | 481 | 5,783 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 1,713 | 1,708 | 1,704 | 1,699 | 1,695 | 1,690 | 1,686 | 1,681 | 1,676 | 1,672 | 1,667 | 1,662 | 20,253 |
| | a Recoverable Costs Allocated to Energy | | 132 | 131 | 131 | 131 | 130 | 130 | 130 | 129 | 129 | 129 | 128 | 128 | 1,558 |
| | b Recoverable Costs Allocated to Demand | | 1,581 | 1,577 | 1,573 | 1,568 | 1,565 | 1,560 | 1,556 | 1,552 | 1,547 | 1,543 | 1,539 | 1,534 | 18,695 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 127 | 127 | 127 | 127 | 126 | 126 | 126 | 125 | 125 | 125 | 124 | 124 | 1,509 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 1,526 | 1,522 | 1,518 | 1,513 | 1,510 | 1,505 | 1,502 | 1,498 | 1,493 | 1,489 | 1,485 | 1,480 | 18,041 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 1,653 | 1,649 | 1,645 | 1,640 | 1,636 | 1,631 | 1,628 | 1,623 | 1,618 | 1,614 | 1,609 | 1,604 | 19,550 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E. 1535
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | |
| 3 | Less: Accumulated Depreciation (C) | (3,329,065) | (3,369,783) | (3,410,501) | (3,451,219) | (3,491,937) | (3,532,655) | (3,573,373) | (3,614,091) | (3,654,809) | (3,695,527) | (3,736,244) | (3,776,962) | (3,817,679) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 9,913,404 | 9,872,686 | 9,831,968 | 9,791,250 | 9,750,532 | 9,709,814 | 9,669,096 | 9,628,378 | 9,587,660 | 9,546,942 | 9,506,225 | 9,465,507 | 9,424,790 | |
| 6 | Average Net Investment | | 9,893,045 | 9,852,327 | 9,811,609 | 9,770,891 | 9,730,173 | 9,689,455 | 9,648,737 | 9,608,019 | 9,567,301 | 9,526,584 | 9,485,866 | 9,445,149 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 72,684 | 72,385 | 72,086 | 71,787 | 71,488 | 71,188 | 70,889 | 70,590 | 70,291 | 69,992 | 69,693 | 69,394 | 852,467 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 20,647 | 20,562 | 20,477 | 20,392 | 20,307 | 20,222 | 20,137 | 20,052 | 19,967 | 19,882 | 19,797 | 19,712 | 242,154 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 30,894 | 30,895 | 30,894 | 370,738 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 117,876 |
| | d Property Taxes | | 30,294 | 30,294 | 30,294 | 30,294 | 30,294 | 30,294 | 30,294 | 30,293 | 30,294 | 30,294 | 30,294 | 30,294 | 363,527 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 164,343 | 163,959 | 163,575 | 163,191 | 162,807 | 162,422 | 162,038 | 161,653 | 161,270 | 160,885 | 160,502 | 160,117 | 1,946,762 |
| | a Recoverable Costs Allocated to Energy | | 12,642 | 12,612 | 12,583 | 12,553 | 12,524 | 12,494 | 12,464 | 12,435 | 12,405 | 12,376 | 12,346 | 12,317 | 149,751 |
| | b Recoverable Costs Allocated to Demand | | 151,701 | 151,347 | 150,992 | 150,638 | 150,283 | 149,928 | 149,574 | 149,218 | 148,865 | 148,509 | 148,156 | 147,800 | 1,797,011 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 12,192 | 12,198 | 12,194 | 12,179 | 12,144 | 12,112 | 12,092 | 12,049 | 12,018 | 11,989 | 11,941 | 11,887 | 144,995 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 146,394 | 146,053 | 145,710 | 145,368 | 145,026 | 144,683 | 144,342 | 143,998 | 143,658 | 143,314 | 142,973 | 142,630 | 1,734,149 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 158,586 | 158,251 | 157,904 | 157,547 | 157,170 | 156,795 | 156,434 | 156,047 | 155,676 | 155,303 | 154,914 | 154,517 | 1,879,144 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 2.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Shield Water Project
P.E. 1620
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | |
| 3 | Less: Accumulated Depreciation (C) | (1,777) | (1,909) | (2,041) | (2,173) | (2,305) | (2,437) | (2,569) | (2,701) | (2,833) | (2,965) | (3,096) | (3,228) | (3,359) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 46,129 | 45,997 | 45,865 | 45,733 | 45,601 | 45,469 | 45,337 | 45,205 | 45,073 | 44,941 | 44,810 | 44,678 | 44,547 | |
| 6 | Average Net Investment | | 46,063 | 45,931 | 45,799 | 45,667 | 45,535 | 45,403 | 45,271 | 45,139 | 45,007 | 44,876 | 44,744 | 44,613 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 338 | 337 | 336 | 336 | 335 | 334 | 333 | 332 | 331 | 330 | 329 | 328 | 3,999 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 96 | 96 | 96 | 95 | 95 | 95 | 94 | 94 | 94 | 94 | 93 | 93 | 1,135 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 131 | 132 | 131 | 1,582 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 566 | 565 | 564 | 563 | 562 | 561 | 559 | 558 | 557 | 555 | 554 | 552 | 6,716 |
| | a Recoverable Costs Allocated to Energy | | 44 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 42 | 516 |
| | b Recoverable Costs Allocated to Demand | | 522 | 522 | 521 | 520 | 519 | 518 | 516 | 515 | 514 | 512 | 511 | 510 | 6,200 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 41 | 503 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 504 | 504 | 503 | 502 | 501 | 500 | 498 | 497 | 496 | 494 | 493 | 492 | 5,984 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 546 | 546 | 545 | 544 | 543 | 542 | 540 | 539 | 538 | 536 | 535 | 533 | 6,487 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | |
| 3 | Less: Accumulated Depreciation (C) | (339,828) | (344,749) | (349,669) | (354,589) | (359,510) | (364,430) | (369,350) | (374,271) | (379,192) | (384,112) | (389,033) | (393,954) | (398,875) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 118,091 | 113,170 | 108,250 | 103,330 | 98,409 | 93,489 | 88,569 | 83,648 | 78,727 | 73,807 | 68,886 | 63,965 | 59,044 | |
| 6 | Average Net Investment | | 115,631 | 110,710 | 105,790 | 100,870 | 95,949 | 91,029 | 86,109 | 81,188 | 76,267 | 71,347 | 66,426 | 61,505 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 850 | 813 | 777 | 741 | 705 | 669 | 633 | 596 | 560 | 524 | 488 | 452 | 7,808 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 241 | 231 | 221 | 211 | 200 | 190 | 180 | 169 | 159 | 149 | 139 | 128 | 2,218 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b Amortization (F) | | 4,921 | 4,920 | 4,920 | 4,921 | 4,920 | 4,920 | 4,921 | 4,921 | 4,920 | 4,921 | 4,921 | 4,921 | 59,047 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 6,012 | 5,964 | 5,918 | 5,873 | 5,825 | 5,779 | 5,734 | 5,686 | 5,639 | 5,594 | 5,548 | 5,501 | 69,073 |
| | a Recoverable Costs Allocated to Energy | | 462 | 459 | 455 | 452 | 448 | 445 | 441 | 437 | 434 | 430 | 427 | 423 | 5,313 |
| | b Recoverable Costs Allocated to Demand | | 5,550 | 5,505 | 5,463 | 5,421 | 5,377 | 5,334 | 5,293 | 5,249 | 5,205 | 5,164 | 5,121 | 5,078 | 63,760 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 446 | 444 | 441 | 439 | 434 | 431 | 428 | 423 | 420 | 417 | 413 | 408 | 5,144 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 5,356 | 5,312 | 5,272 | 5,231 | 5,189 | 5,147 | 5,108 | 5,065 | 5,023 | 4,983 | 4,942 | 4,900 | 61,528 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 5,802 | 5,756 | 5,713 | 5,670 | 5,623 | 5,578 | 5,536 | 5,488 | 5,443 | 5,400 | 5,355 | 5,308 | 66,672 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) 7 year amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Capital Investments, Depreciation and Taxes
For Project: Crist DEP Project
P.E. 1199
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 227,262 | |
| | b Clearings to Plant (J) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 227,262 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 227,262 | |
| 3 | Less: Accumulated Depreciation (C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (369) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 226,893 | |
| 6 | Average Net Investment | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 113,447 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 833 | 833 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 237 | 237 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 369 | 369 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,439 | 1,439 |
| | a Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,439 | 1,439 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,389 | 1,389 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,389 | 1,389 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) PE 1199 qualified for AFUDC during construction. It became a part of ECRC calcs., when the 1st part of Phase I went into service.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
**January 2003 - December 2003**

Return on Working Capital, SO2 Expenses
For Project: SO2 Allowances

(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Actual July | Actual August | Actual September | Actual October | Actual November | Actual December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Purchases/Transfers | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Sales/Transfers | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Auction Proceeds/Other | | 0 | 0 | 0 | 0 | 0 | 216,362 | (34,927) | 19,906 | 0 | 0 | 0 | 0 | |
| 2 | Working Capital | | | | | | | | | | | | | | |
| | a FERC 158.1 Allowance Inventory | 32,680 | 31,577 | 30,852 | 30,183 | 29,282 | 28,269 | 27,156 | 25,719 | 24,471 | 23,310 | 22,180 | 21,129 | 19,941 | |
| | b FERC 158.2 Allowances Withheld | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c FERC 182.3 Other Regl. Assets - Losses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d FERC 254 Regulatory Liabilities - Gains | (650,060) | (644,705) | (639,351) | (633,996) | (628,642) | (623,287) | (812,451) | (750,326) | (743,034) | (715,837) | (688,639) | (661,441) | (662,537) | |
| 3 | Total Working Capital Balance | (617,380) | (613,128) | (608,499) | (603,813) | (599,360) | (595,018) | (785,295) | (724,607) | (718,563) | (692,527) | (666,459) | (640,312) | (642,596) | |
| 4 | Average Net Working Capital Balance | | (615,254) | (610,814) | (606,156) | (601,587) | (597,189) | (690,157) | (754,951) | (721,585) | (705,545) | (679,493) | (653,386) | (641,454) | |
| 5 | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (A) | | (4,520) | (4,488) | (4,453) | (4,420) | (4,388) | (5,071) | (5,547) | (5,301) | (5,184) | (4,992) | (4,800) | (4,713) | (57,877) |
| | b Debt Component (Line 4 x 3.5137% x 1/12) | | (1,284) | (1,275) | (1,265) | (1,256) | (1,246) | (1,440) | (1,576) | (1,506) | (1,472) | (1,418) | (1,364) | (1,339) | (16,441) |
| 6 | Total Return Component (D) | | (5,804) | (5,763) | (5,718) | (5,676) | (5,634) | (6,511) | (7,123) | (6,807) | (6,656) | (6,410) | (6,164) | (6,052) | (74,318) |
| 7 | Expenses | | | | | | | | | | | | | | |
| | a Gains | | (5,355) | (5,355) | (5,355) | (5,355) | (5,355) | (27,198) | (27,198) | (27,198) | (27,198) | (27,198) | (27,198) | 1,096 | (188,867) |
| | b Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c SO2 Allowance Expense | | 1,103 | 725 | 669 | 901 | 1,013 | 1,113 | 1,437 | 1,248 | 1,161 | 1,130 | 1,051 | 1,188 | 12,739 |
| 8 | Net Expenses (E) | | (4,252) | (4,630) | (4,686) | (4,454) | (4,342) | (26,085) | (25,761) | (25,950) | (26,037) | (26,068) | (26,147) | 2,284 | (176,128) |
| 9 | Total System Recoverable Expenses (Lines 6 + 7) | | (10,056) | (10,393) | (10,404) | (10,130) | (9,976) | (32,596) | (32,884) | (32,757) | (32,693) | (32,478) | (32,311) | (3,768) | (250,446) |
| | a Recoverable Costs Allocated to Energy | | (10,056) | (10,393) | (10,404) | (10,130) | (9,976) | (32,596) | (32,884) | (32,757) | (32,693) | (32,478) | (32,311) | (3,768) | (250,446) |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9637519 | 0.9665363 | 0.9684383 | 0.9695202 | 0.9689702 | 0.9687608 | 0.9694619 | 0.9682549 | 0.9681497 | 0.9680716 | 0.9665352 | 0.9644503 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (B) | | (9,698) | (10,052) | (10,083) | (9,828) | (9,673) | (31,600) | (31,902) | (31,739) | (31,674) | (31,463) | (31,252) | (3,637) | (242,601) |
| 13 | Retail Demand-Related Recoverable Costs (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | (9,698) | (10,052) | (10,083) | (9,828) | (9,673) | (31,600) | (31,902) | (31,739) | (31,674) | (31,463) | (31,252) | (3,637) | (242,601) |

Notes:
(A) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6A and 7A
(E) Line 8 is reported on Schedule 4A and 5A

**Schedule 1E**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
**January 2004 - December 2004**

| Line | | Period Amount ($) |
|---|---|---|
| 1 | Over/(Under) Recovery for the current period (Schedule 2E, Line 5) | (127,089) |
| 2 | Interest Provision (Schedule 2E, Line 6) | 12,962 |
| 3 | Sum of Current Period Adjustments (Schedule 2E, Line 10) | 476 |
| 4 | Current Period True-Up Amount to be refunded/(recovered) in the projection period January 2005 - December 2005 (Lines 1 + 2 + 3) | (113,651) |

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040007-EI EXHIBIT NO. 16
COMPANY/ Gulf Power
WITNESS: T. A. Davis
DATE 11-08-04

Schedule 2E

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
**January 2004 - December 2004**

**Current Period True-Up Amount**
(in Dollars)

| Line | | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ECRC Revenues (net of Revenue Taxes) | 1,208,430 | 1,074,419 | 993,342 | 985,885 | 1,263,644 | 1,387,421 | 1,445,411 | 1,445,331 | 1,196,957 | 1,057,963 | 916,620 | 1,049,637 | 14,025,060 |
| 2 | True-Up Provision (Order No. PSC-03-1348-FOF-EI) | 36,564 | 36,564 | 36,563 | 36,564 | 36,563 | 36,563 | 36,564 | 36,564 | 36,563 | 36,564 | 36,564 | 36,563 | 438,763 |
| 3 | **ECRC Revenues Applicable to Period (Lines 1 + 2)** | 1,244,994 | 1,110,983 | 1,029,905 | 1,022,449 | 1,300,207 | 1,423,984 | 1,481,975 | 1,481,895 | 1,233,520 | 1,094,527 | 953,184 | 1,086,200 | 14,463,823 |
| 4 | Jurisdictional ECRC Costs | | | | | | | | | | | | | |
| | a O & M Activities (Schedule 5E, Line 9) | 148,830 | 866,139 | 96,142 | 98,220 | 104,527 | 123,332 | 138,323 | 300,699 | 176,678 | 163,264 | 167,715 | 190,918 | 2,574,787 |
| | b Capital Investment Projects (Schedule 7E, Line 9) | 683,275 | 691,579 | 703,791 | 932,252 | 1,151,710 | 1,150,202 | 1,132,656 | 1,117,663 | 1,115,233 | 1,114,781 | 1,111,533 | 1,111,450 | 12,016,125 |
| | c **Total Jurisdictional ECRC Costs** | 832,105 | 1,557,718 | 799,933 | 1,030,472 | 1,256,237 | 1,273,534 | 1,270,979 | 1,418,362 | 1,291,911 | 1,278,045 | 1,279,248 | 1,302,368 | 14,590,912 |
| 5 | **Over/(Under) Recovery (Line 3 - Line 4c)** | 412,889 | (446,735) | 229,972 | (8,023) | 43,970 | 150,450 | 210,996 | 63,533 | (58,391) | (183,518) | (326,064) | (216,168) | (127,089) |
| 6 | Interest Provision (Schedule 3E, Line 10) | 1,096 | 1,011 | 868 | 953 | 966 | 1,167 | 1,311 | 1,412 | 1,379 | 1,225 | 939 | 635 | 12,962 |
| 7 | Beginning Balance True-Up & Interest Provision | 438,763 | 816,660 | 334,372 | 528,649 | 485,015 | 493,388 | 608,442 | 784,185 | 812,566 | 718,991 | 500,134 | 138,445 | 438,763 |
| | a Deferred True-Up from January 2003 - December 2003 (Schedule 1A, Line 3) | 631,135 | 631,135 | 631,135 | 631,135 | 631,135 | 631,135 | 631,135 | 631,135 | 631,135 | 631,135 | 631,135 | 631,135 | 631,135 |
| 8 | True-Up Collected/(Refunded) (see Line 2) | (36,564) | (36,564) | (36,563) | (36,564) | (36,563) | (36,563) | (36,564) | (36,564) | (36,563) | (36,564) | (36,564) | (36,563) | (438,763) |
| 9 | End of Period Total True-Up (Lines 5 + 6 + 7 + 7a + 8) | 1,447,319 | 965,507 | 1,159,784 | 1,116,150 | 1,124,523 | 1,239,577 | 1,415,320 | 1,443,701 | 1,350,126 | 1,131,269 | 769,580 | 517,484 | 517,008 |
| 10 | Adjustments to Period Total True-Up Including Interest * | 476 | | | | | | | | | | | | 476 |
| 11 | **Current Period Total Net True-Up (Lines 9 + 10)** | 1,447,795 | 965,507 | 1,159,784 | 1,116,150 | 1,124,523 | 1,239,577 | 1,415,320 | 1,443,701 | 1,350,126 | 1,131,269 | 769,580 | 517,484 | 517,484 |

** Adjustment per audit finding to O&M expense*

Schedule 3E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Interest Provision
(in Dollars)

| Line | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 Beg. True-Up Amount (Schedule 2E, Lines 7 + 7a + 10) | 1,070,374 | 1,447,795 | 965,507 | 1,159,784 | 1,116,150 | 1,124,523 | 1,239,577 | 1,415,320 | 1,443,701 | 1,350,126 | 1,131,269 | 769,580 | |
| 2 Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8) | 1,446,699 | 964,496 | 1,158,916 | 1,115,197 | 1,123,557 | 1,238,410 | 1,414,009 | 1,442,289 | 1,348,747 | 1,130,044 | 768,641 | 516,849 | |
| 3 Total of Beginning & Ending True-up (Lines 1 + 2) | 2,517,073 | 2,412,291 | 2,124,423 | 2,274,981 | 2,239,707 | 2,362,933 | 2,653,586 | 2,857,609 | 2,792,448 | 2,480,170 | 1,899,910 | 1,286,429 | |
| 4 Average True-Up Amount (Line 3 x 1/2) | 1,258,537 | 1,206,146 | 1,062,212 | 1,137,491 | 1,119,854 | 1,181,467 | 1,326,793 | 1,428,805 | 1,396,224 | 1,240,085 | 949,955 | 643,215 | |
| 5 Interest Rate (First Day of Reporting Business Month) | 0.010600 | 0.010300 | 0.009800 | 0.009800 | 0.010300 | 0.010400 | 0.013300 | 0.010400 | 0.013300 | 0.010400 | 0.013300 | 0.010400 | |
| 6 Interest Rate (First Day of Subsequent Business Month) | 0.010300 | 0.009800 | 0.009800 | 0.010300 | 0.010400 | 0.013300 | 0.010400 | 0.013300 | 0.010400 | 0.013300 | 0.010400 | 0.013300 | |
| 7 Total of Beginning and Ending Interest Rates (Line 5 + Line 6) | 0.020900 | 0.020100 | 0.019600 | 0.020100 | 0.020700 | 0.023700 | 0.023700 | 0.023700 | 0.023700 | 0.023700 | 0.023700 | 0.023700 | |
| 8 Average Interest Rate (Line 7 x 1/2) | 0.010450 | 0.010050 | 0.009800 | 0.010050 | 0.010350 | 0.011850 | 0.011850 | 0.011850 | 0.011850 | 0.011850 | 0.011850 | 0.011850 | |
| 9 Monthly Average Interest Rate (Line 8 x 1/12) | 0.000871 | 0.000838 | 0.000817 | 0.000838 | 0.000863 | 0.000988 | 0.000988 | 0.000988 | 0.000988 | 0.000988 | 0.000988 | 0.000988 | |
| 10 Interest Provision for the Month (Line 4 x Line 9) | 1,096 | 1,011 | 868 | 953 | 966 | 1,167 | 1,311 | 1,412 | 1,379 | 1,225 | 939 | 635 | 12,962 |

Schednle 4E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
**January 2004 - December 2004**

**Variance Report of O & M Activities**
(in Dollars)

| Line | | (1) Estimated/ Actual | (2) Original Projection | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1 | Description of O & M Activities | | | | |
| .1 | Sulfur | 1,762 | 0 | 1,762 | 100.0 % |
| .2 | Air Emission Fees | 789,874 | 789,874 | 0 | 0.0 % |
| .3 | Title V | 94,136 | 94,136 | 0 | 0.0 % |
| .4 | Asbestos Fees | 1,500 | 2,000 | (500) | (25.0) % |
| .5 | Emission Monitoring | 488,968 | 488,968 | 0 | 0.0 % |
| .6 | General Water Quality | 265,655 | 340,655 | (75,000) | (22.0) % |
| .7 | Groundwater Contamination Investigation | 922,143 | 922,143 | 0 | 0.0 % |
| .8 | State NPDES Administration | 46,885 | 42,000 | 4,885 | 11.6 % |
| .9 | Lead and Copper Rule | 9,000 | 9,000 | 0 | 0.0 % |
| .10 | Env Auditing/Assessment | 10,382 | 5,000 | 5,382 | 107.6 % |
| .11 | General Solid & Hazardous Waste | 209,126 | 209,126 | 0 | 0.0 % |
| .12 | Above Ground Storage Tanks | 65,000 | 65,000 | 0 | 0.0 % |
| .13 | Low Nox | 1,084 | 0 | 1,084 | 100.0 % |
| .14 | Ash Pond Diversion Curtains | 0 | 0 | 0 | 0.0 % |
| .15 | Mercury Emissions | 0 | 0 | 0 | 0.0 % |
| .16 | Sodium Injection | 13,473 | 0 | 13,473 | 100.0 % |
| .17 | Gulf Coast Ozone Study | 10,000 | 20,000 | (10,000) | (50.0) % |
| .18 | SPCC Substation Project | 62,217 | 100,000 | (37,783) | (37.8) % |
| .19 | SO2 Allowances | (325,382) | (82,143) | (243,239) | 296.1 % |
| 2 | **Total O & M Activities** | 2,665,823 | 3,005,759 | (339,936) | (11.3) % |
| 3 | Recoverable Costs Allocated to Energy | 1,073,915 | 1,310,835 | (236,920) | (18.1) % |
| 4 | Recoverable Costs Allocated to Demand | 1,591,908 | 1,694,924 | (103,016) | (6.1) % |

Notes:

Column (1) is the End of Period Totals on Schedule 5E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI
Column (3) = Column (1) - Column (2)

Schedule 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

O & M Activities
(In Dollars)

| Line | | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period 12-Month | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of O & M Activities | | | | | | | | | | | | | | | |
| | .1 Sulfur | - | 1,762 | - | - | - | - | - | - | - | - | - | - | 1,762 | | 1,762 |
| | .2 Air Emission Fees | - | 662,978 | - | - | - | - | - | 126,896 | - | - | - | - | 789,874 | | 789,874 |
| | .3 Title V | 5,092 | 6,367 | 3,087 | 5,416 | 5,633 | 5,795 | 9,137 | 9,137 | 11,637 | 11,731 | 8,908 | 12,196 | 94,136 | | 94,136 |
| | .4 Asbestos Fees | - | 1,000 | - | - | - | - | - | - | - | - | - | 500 | 1,500 | 1,500 | |
| | .5 Emission Monitoring | 24,221 | 53,592 | 19,538 | 25,367 | 52,114 | 54,164 | 51,344 | 36,257 | 46,257 | 40,394 | 38,597 | 47,123 | 488,968 | | 488,968 |
| | .6 General Water Quality | 22,676 | 8,712 | 10,726 | 20,280 | 12,633 | 11,867 | 29,283 | 25,880 | 26,082 | 27,604 | 31,062 | 38,850 | 265,655 | 265,655 | |
| | .7 Groundwater Contamination Investigation | 39,993 | 121,235 | 36,533 | 35,871 | 39,541 | 36,956 | 97,551 | 99,940 | 99,046 | 103,900 | 113,069 | 98,508 | 922,143 | 922,143 | |
| | .8 State NPDES Administration | 46,000 | 17 | 218 | - | - | - | - | 450 | - | 200 | - | - | 46,885 | 46,885 | |
| | .9 Lead and Copper Rule | 59 | 59 | 6,190 | 59 | - | - | 160 | 160 | 910 | 190 | 200 | 1,013 | 9,000 | 9,000 | |
| | .10 Env Auditing/Assessment | 143 | - | - | 1,488 | 5,145 | 106 | 1,500 | 1,500 | 500 | - | - | - | 10,382 | 10,382 | |
| | .11 General Solid & Hazardous Waste | 5,160 | 21,854 | 16,669 | 20,261 | 23,519 | 18,590 | 16,504 | 16,506 | 17,331 | 15,864 | 17,722 | 19,146 | 209,126 | 209,126 | |
| | .12 Above Ground Storage Tanks | 16,500 | 6,146 | 4,727 | 172 | 2,254 | 7,083 | - | - | 11,868 | - | - | 16,250 | 65,000 | 65,000 | |
| | .13 Low Nox | - | 1,084 | - | - | - | - | - | - | - | - | - | - | 1,084 | | 1,084 |
| | .14 Ash Pond Diversion Curtains | - | - | - | - | - | - | - | - | - | - | - | - | 0 | | 0 |
| | .15 Mercury Emissions | - | - | - | - | - | - | - | - | - | - | - | - | 0 | | 0 |
| | .16 Sodium Injection | - | - | 8,843 | - | 4,630 | - | - | - | - | - | - | - | 13,473 | | 13,473 |
| | .17 Gulf Coast Ozone Study | 1,330 | 18,420 | - | - | - | 28,143 | (45,118) | 1,445 | 1,445 | 1,445 | 1,445 | 1,445 | 10,000 | | 10,000 |
| | .18 SPCC Substation Project | - | - | - | - | - | 2,217 | 20,000 | 30,000 | 5,000 | 5,000 | - | - | 62,217 | 62,217 | |
| | .19 SO2 Allowances | (6,972) | (7,064) | (7,014) | (7,237) | (37,269) | (37,350) | (36,963) | (36,962) | (37,018) | (37,166) | (37,190) | (37,177) | (325,382) | | (325,382) |
| 2 | Total of O & M Activities | 154,202 | 896,162 | 99,517 | 101,677 | 108,200 | 127,571 | 143,398 | 311,209 | 183,058 | 169,162 | 173,813 | 197,854 | 2,665,823 | 1,591,908 | 1,073,915 |
| 3 | Recoverable Costs Allocated to Energy | 23,671 | 737,139 | 24,454 | 23,546 | 25,108 | 50,752 | (21,600) | 136,773 | 22,321 | 16,404 | 11,760 | 23,587 | 1,073,915 | | |
| 4 | Recoverable Costs Allocated to Demand | 130,531 | 159,023 | 75,063 | 78,131 | 83,092 | 76,819 | 164,998 | 174,436 | 160,737 | 152,758 | 162,053 | 174,267 | 1,591,908 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | | | |
| 6 | Retail Demand Jurisdictional Factor | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | 22,865 | 712,679 | 23,705 | 22,822 | 24,342 | 49,200 | (20,903) | 132,365 | 21,564 | 15,850 | 11,331 | 22,747 | 1,038,567 | | |
| 8 | Jurisdictional Demand Recoverable Costs (B) | 125,965 | 153,460 | 72,437 | 75,398 | 80,185 | 74,132 | 159,226 | 168,334 | 155,114 | 147,414 | 156,384 | 168,171 | 1,536,220 | | |
| 9 | Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8) | 148,830 | 866,139 | 96,142 | 98,220 | 104,527 | 123,332 | 138,323 | 300,699 | 176,678 | 163,264 | 167,715 | 190,918 | 2,574,787 | | |

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

**Schedule 6E**

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
**January 2004 - December 2004**

**Variance Report of Capital Investment Projects - Recoverable Costs**
(in Dollars)

| Line | | (1) Estimated/ Actual | (2) Original Projected | (3) Variance Amount | (4) Variance Percent |
|---|---|---|---|---|---|
| 1 | Description of Investment Projects | | | | |
| .1 | Air Quality Assurance Testing | 21,762 | 21,757 | 5 | 0.0 % |
| .2 | Crist 5, 6 & 7 Precipitator Projects | 2,541,640 | 2,511,043 | 30,597 | 1.2 % |
| .3 | Crist 7 Flue Gas Conditioning | 240,354 | 240,354 | 0 | 0.0 % |
| .4 | Low NOx Burners, Crist 6 & 7 | 2,286,376 | 2,394,729 | (108,353) | (4.5) % |
| .5 | CEMS - Crist, Scholz, Smith, & Daniel | 721,287 | 761,744 | (40,457) | (5.3) % |
| .6 | Sub. Contam. Mobile Groundwater Treat. Sys. | 116,989 | 116,989 | 0 | 0.0 % |
| .7 | Raw Water Well Flowmeters - Plants Crist & Smith | 33,392 | 33,392 | 0 | 0.0 % |
| .8 | Crist Cooling Tower Cell | 100,305 | 100,305 | 0 | 0.0 % |
| .9 | Crist 1-5 Dechlorination | 35,504 | 35,504 | 0 | 0.0 % |
| .10 | Crist Diesel Fuel Oil Remediation | 6,102 | 7,921 | (1,819) | (23.0) % |
| .11 | Crist Bulk Tanker Unload Sec Contain Struc | 11,813 | 11,813 | 0 | 0.0 % |
| .12 | Crist IWW Sampling System | 6,897 | 6,897 | 0 | 0.0 % |
| .13 | Smith Sodium Injection System | 13,790 | 13,790 | 0 | 0.0 % |
| .14 | Smith Stormwater Collection System | 321,060 | 321,060 | 0 | 0.0 % |
| .15 | Smith Waste Water Treatment Facility | 24,752 | 19,599 | 5,153 | 26.3 % |
| .16 | Daniel Ash Management Project | 1,855,986 | 1,873,530 | (17,544) | (0.9) % |
| .17 | Smith Shield Water Project | 6,538 | 6,538 | 0 | 0.0 % |
| .18 | Underground Fuel Tank Replacement | 62,388 | 62,388 | 0 | 0.0 % |
| .19 | Crist FDEP Agreement for Ozone Attainment | 4,094,002 | 3,105,796 | 988,206 | 31.8 % |
| .20 | Crist Switchyard Stormwater | 7,480 | 7,478 | 2 | 0.0 % |
| .21 | Crist Common FTIR Monitor | 3,400 | 7,140 | (3,740) | (52.4) % |
| .22 | SO2 Allowances | (81,995) | (66,639) | (15,356) | (24.6) % |
| 2 | Total Investment Projects - Recoverable Costs | 12,429,822 | 11,593,128 | 836,694 | 7.2 % |
| 3 | Recoverable Costs Allocated to Energy | 10,039,788 | 9,189,979 | 849,809 | 9.2 % |
| 4 | Recoverable Costs Allocated to Demand | 2,390,034 | 2,403,149 | (13,115) | (0.5) % |

Notes:
Column (1) is the End of Period Totals on Schedule 7E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-03-1348-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Schedule 7E

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
**Calculation of the Current Period Estimated True-Up Amount**
**January 2004 - December 2004**

**Capital Investment Projects - Recoverable Costs**
**(in Dollars)**

| Line | | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects (A) | | | | | | | | | | | | | | | |
| | .1 Air Quality Assurance Testing | 1,869 | 1,858 | 1,848 | 1,838 | 1,829 | 1,818 | 1,808 | 1,798 | 1,788 | 1,777 | 1,768 | 1,758 | 21,762 | 0 | 21,762 |
| | .2 Crist 5, 6 & 7 Precipitator Projects | 230,861 | 229,985 | 229,108 | 228,219 | 227,480 | 226,739 | 209,753 | 192,951 | 192,425 | 191,899 | 191,373 | 190,847 | 2,541,640 | 0 | 2,541,640 |
| | .3 Crist 7 Flue Gas Conditioning | 20,410 | 20,341 | 20,271 | 20,203 | 20,133 | 20,065 | 19,995 | 19,926 | 19,856 | 19,788 | 19,717 | 19,649 | 240,354 | 0 | 240,354 |
| | .4 Low NOx Burners, Crist 6 & 7 | 172,776 | 177,042 | 190,245 | 200,906 | 196,053 | 190,581 | 192,340 | 194,094 | 193,690 | 193,286 | 192,883 | 192,480 | 2,286,376 | 0 | 2,286,376 |
| | .5 CEMS - Crist, Scholz, Smith, & Daniel | 59,940 | 59,831 | 59,723 | 59,614 | 59,505 | 59,397 | 59,250 | 59,481 | 60,113 | 60,759 | 61,514 | 62,160 | 721,287 | 0 | 721,287 |
| | .6 Sub. Contam. Mobile Groundwater Treat. Sys. | 9,855 | 9,835 | 9,817 | 9,798 | 9,779 | 9,759 | 9,739 | 9,720 | 9,701 | 9,682 | 9,663 | 9,641 | 116,989 | 107,989 | 9,000 |
| | .7 Raw Water Well Flowmeters - Plants Crist & Smith | 2,820 | 2,814 | 2,807 | 2,800 | 2,793 | 2,786 | 2,779 | 2,772 | 2,765 | 2,759 | 2,751 | 2,746 | 33,392 | 30,823 | 2,569 |
| | .8 Crist Cooling Tower Cell | 8,523 | 8,493 | 8,463 | 8,432 | 8,403 | 8,373 | 8,345 | 8,315 | 8,285 | 8,255 | 8,223 | 8,195 | 100,305 | 92,589 | 7,716 |
| | .9 Crist 1-5 Dechlorination | 3,010 | 3,000 | 2,991 | 2,982 | 2,973 | 2,963 | 2,954 | 2,945 | 2,935 | 2,926 | 2,917 | 2,908 | 35,504 | 32,772 | 2,732 |
| | .10 Crist Diesel Fuel Oil Remediation | 467 | 465 | 464 | 463 | 460 | 459 | 458 | 480 | 526 | 572 | 617 | 671 | 6,102 | 5,633 | 469 |
| | .11 Crist Bulk Tanker Unload Sec Contain Struc | 1,002 | 999 | 995 | 992 | 989 | 986 | 982 | 980 | 977 | 973 | 971 | 967 | 11,813 | 10,904 | 909 |
| | .12 Crist IWW Sampling System | 584 | 583 | 582 | 579 | 578 | 575 | 574 | 572 | 570 | 569 | 566 | 565 | 6,897 | 6,366 | 531 |
| | .13 Smith Sodium Injection System | 1,165 | 1,161 | 1,159 | 1,156 | 1,153 | 1,151 | 1,148 | 1,145 | 1,142 | 1,139 | 1,137 | 1,134 | 13,790 | 0 | 13,790 |
| | .14 Smith Stormwater Collection System | 27,152 | 27,080 | 27,008 | 26,936 | 26,863 | 26,791 | 26,719 | 26,647 | 26,574 | 26,502 | 26,430 | 26,358 | 321,060 | 296,362 | 24,698 |
| | .15 Smith Waste Water Treatment Facility | 1,658 | 1,654 | 1,649 | 1,645 | 1,711 | 1,777 | 1,795 | 1,838 | 2,023 | 2,677 | 3,166 | 3,159 | 24,752 | 22,848 | 1,904 |
| | .16 Daniel Ash Management Project | 156,778 | 156,394 | 156,010 | 155,626 | 155,242 | 154,858 | 154,473 | 154,089 | 153,705 | 153,321 | 152,937 | 152,553 | 1,855,986 | 1,713,218 | 142,768 |
| | .17 Smith Shield Water Project | 552 | 551 | 549 | 548 | 547 | 545 | 544 | 543 | 542 | 540 | 539 | 538 | 6,538 | 6,036 | 502 |
| | .18 Underground Fuel Tank Replacement | 5,455 | 5,408 | 5,362 | 5,315 | 5,268 | 5,223 | 5,175 | 5,130 | 5,083 | 5,037 | 4,989 | 4,943 | 62,388 | 57,589 | 4,799 |
| | .19 Crist FDEP Agreement for Ozone Attainment | 8,701 | 14,157 | 13,774 | 240,486 | 474,401 | 481,004 | 479,835 | 478,666 | 477,497 | 476,329 | 475,160 | 473,992 | 4,094,002 | 0 | 4,094,002 |
| | .20 Crist Switchyard Stormwater | 0 | 0 | 0 | 0 | 0 | 1 | 197 | 589 | 982 | 1,376 | 1,769 | 2,566 | 7,480 | 6,905 | 575 |
| | .21 Crist Common FTIR Monitor | 0 | 0 | 0 | 0 | 0 | 0 | 89 | 372 | 664 | 760 | 759 | 756 | 3,400 | 0 | 3,400 |
| | .22 SO2 Allowances | (6,030) | (5,963) | (5,896) | (5,830) | (7,301) | (8,470) | (7,957) | (7,609) | (7,260) | (6,911) | (6,559) | (6,209) | (81,995) | 0 | (81,995) |
| 2 | Total Investment Projects - Recoverable Costs | 707,548 | 715,688 | 726,929 | 962,708 | 1,188,859 | 1,187,381 | 1,170,995 | 1,155,444 | 1,154,583 | 1,154,015 | 1,153,290 | 1,152,377 | 12,429,822 | 2,390,034 | 10,039,788 |
| 3 | Recoverable Costs Allocated to Energy | 506,453 | 515,124 | 526,902 | 763,218 | 989,836 | 988,831 | 972,779 | 957,333 | 956,428 | 955,381 | 954,331 | 953,167 | 10,039,788 | | |
| 4 | Recoverable Costs Allocated to Demand | 201,095 | 200,564 | 200,027 | 199,490 | 199,023 | 198,550 | 198,216 | 198,111 | 198,155 | 198,634 | 198,959 | 199,210 | 2,390,034 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | | | |
| 6 | Retail Demand Jurisdictional Factor | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (B) | 489,215 | 498,031 | 510,761 | 739,740 | 959,649 | 958,598 | 941,374 | 926,482 | 924,010 | 923,095 | 919,534 | 919,209 | 9,709,698 | | |
| 8 | Jurisdictional Demand Recoverable Costs (C) | 194,060 | 193,548 | 193,030 | 192,512 | 192,061 | 191,604 | 191,282 | 191,181 | 191,223 | 191,686 | 191,999 | 192,241 | 2,306,427 | | |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | 683,275 | 691,579 | 703,791 | 932,252 | 1,151,710 | 1,150,202 | 1,132,656 | 1,117,663 | 1,115,233 | 1,114,781 | 1,111,533 | 1,111,450 | 12,016,125 | | |

Notes:

(A) Pages 1-18 of Schedule 8E, Line 9, Page 19 of Schedule 8E, Line 6
(B) Line 3 x Line 5 x Line loss multiplier
(C) Line 4 x Line 6

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | |
| 3 | Less: Accumulated Depreciation © | (243,107) | (244,173) | (245,240) | (246,306) | (247,373) | (248,439) | (249,506) | (250,572) | (251,639) | (252,705) | (253,772) | (254,838) | (255,904) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 85,590 | 84,524 | 83,457 | 82,391 | 81,324 | 80,258 | 79,191 | 78,125 | 77,058 | 75,992 | 74,925 | 73,859 | 72,793 | |
| 6 | Average Net Investment | | 85,057 | 83,991 | 82,924 | 81,858 | 80,791 | 79,725 | 78,658 | 77,592 | 76,525 | 75,459 | 74,392 | 73,326 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 625 | 617 | 609 | 601 | 594 | 586 | 578 | 570 | 562 | 554 | 547 | 539 | 6,982 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 178 | 175 | 173 | 171 | 169 | 166 | 164 | 162 | 160 | 157 | 155 | 153 | 1,983 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b Amortization (F) | | 1,066 | 1,066 | 1,066 | 1,066 | 1,066 | 1,066 | 1,066 | 1,066 | 1,066 | 1,066 | 1,066 | 1,066 | 12,797 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 1,869 | 1,858 | 1,848 | 1,838 | 1,829 | 1,818 | 1,808 | 1,798 | 1,788 | 1,777 | 1,768 | 1,758 | 21,762 |
| | a Recoverable Costs Allocated to Energy | | 1,869 | 1,858 | 1,848 | 1,838 | 1,829 | 1,818 | 1,808 | 1,798 | 1,788 | 1,777 | 1,768 | 1,758 | 21,762 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 1,805 | 1,796 | 1,792 | 1,782 | 1,774 | 1,763 | 1,750 | 1,740 | 1,728 | 1,717 | 1,704 | 1,696 | 21,047 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 1,805 | 1,796 | 1,792 | 1,782 | 1,774 | 1,763 | 1,750 | 1,740 | 1,728 | 1,717 | 1,704 | 1,696 | 21,047 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) 7 year amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.Es 1119, 1216, 1243
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 11,862,909 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 2,818 | 0 | 0 | 31,774 | 0 | 665,408 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 10,000 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 24,440,825 | 12,577,916 | 12,577,916 | 12,577,916 | 12,577,916 | 12,577,916 | 12,577,916 | |
| 3 | Less: Accumulated Depreciation © | (9,920,644) | (10,014,967) | (10,106,472) | (10,200,795) | (10,295,118) | (10,357,668) | (10,451,992) | 1,991,280 | 1,935,512 | 1,879,743 | 1,823,975 | 1,768,207 | 1,712,438 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 14,520,181 | 14,425,858 | 14,334,353 | 14,240,030 | 14,145,707 | 14,083,157 | 13,988,833 | 14,569,196 | 14,513,428 | 14,457,659 | 14,401,891 | 14,346,123 | 14,290,354 | |
| 6 | Average Net Investment | | 14,473,020 | 14,380,106 | 14,287,192 | 14,192,869 | 14,114,432 | 14,035,995 | 14,279,015 | 14,541,312 | 14,485,544 | 14,429,775 | 14,374,007 | 14,318,239 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 106,333 | 105,651 | 104,968 | 104,275 | 103,699 | 103,122 | 104,908 | 106,835 | 106,425 | 106,016 | 105,606 | 105,196 | 1,263,034 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 30,205 | 30,011 | 29,817 | 29,621 | 29,457 | 29,293 | 29,800 | 30,348 | 30,231 | 30,115 | 29,999 | 29,882 | 358,779 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 79,433 | 79,433 | 79,433 | 79,433 | 79,433 | 79,433 | 60,155 | 40,878 | 40,878 | 40,878 | 40,878 | 40,878 | 741,143 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 14,890 | 14,890 | 14,890 | 14,890 | 14,891 | 14,891 | 14,890 | 14,890 | 14,891 | 14,890 | 14,890 | 14,891 | 178,684 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 230,861 | 229,985 | 229,108 | 228,219 | 227,480 | 226,739 | 209,753 | 192,951 | 192,425 | 191,899 | 191,373 | 190,847 | 2,541,640 |
| | a Recoverable Costs Allocated to Energy | | 230,861 | 229,985 | 229,108 | 228,219 | 227,480 | 226,739 | 209,753 | 192,951 | 192,425 | 191,899 | 191,373 | 190,847 | 2,541,640 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 223,003 | 222,353 | 222,089 | 221,199 | 220,542 | 219,807 | 202,981 | 186,733 | 185,903 | 185,414 | 184,395 | 184,048 | 2,458,467 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 223,003 | 222,353 | 222,089 | 221,199 | 220,542 | 219,807 | 202,981 | 186,733 | 185,903 | 185,414 | 184,395 | 184,048 | 2,458,467 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | |
| 3 | Less: Accumulated Depreciation © | (790,082) | (797,421) | (804,761) | (812,100) | (819,440) | (826,779) | (834,119) | (841,458) | (848,798) | (856,137) | (863,477) | (870,816) | (878,156) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 1,389,163 | 1,381,824 | 1,374,484 | 1,367,145 | 1,359,805 | 1,352,466 | 1,345,126 | 1,337,787 | 1,330,447 | 1,323,108 | 1,315,768 | 1,308,429 | 1,301,089 | |
| 6 | Average Net Investment | | 1,385,494 | 1,378,154 | 1,370,815 | 1,363,475 | 1,356,136 | 1,348,796 | 1,341,457 | 1,334,117 | 1,326,778 | 1,319,438 | 1,312,099 | 1,304,759 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 10,179 | 10,125 | 10,071 | 10,017 | 9,964 | 9,910 | 9,856 | 9,802 | 9,748 | 9,694 | 9,640 | 9,586 | 118,592 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 2,892 | 2,876 | 2,861 | 2,846 | 2,830 | 2,815 | 2,800 | 2,784 | 2,769 | 2,754 | 2,738 | 2,723 | 33,688 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 84,996 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 256 | 257 | 256 | 257 | 256 | 257 | 256 | 257 | 256 | 257 | 256 | 257 | 3,078 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 20,410 | 20,341 | 20,271 | 20,203 | 20,133 | 20,065 | 19,995 | 19,926 | 19,856 | 19,788 | 19,717 | 19,649 | 240,354 |
| | a Recoverable Costs Allocated to Energy | | 20,410 | 20,341 | 20,271 | 20,203 | 20,133 | 20,065 | 19,995 | 19,926 | 19,856 | 19,788 | 19,717 | 19,649 | 240,354 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 19,715 | 19,666 | 19,650 | 19,582 | 19,519 | 19,452 | 19,349 | 19,284 | 19,183 | 19,119 | 18,998 | 18,949 | 232,466 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 19,715 | 19,666 | 19,650 | 19,582 | 19,519 | 19,452 | 19,349 | 19,284 | 19,183 | 19,119 | 18,998 | 18,949 | 232,466 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
**January 2004 - December 2004**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, and 1242
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 295,393 | 366,576 | 2,214,406 | 75,486 | 122,681 | 0 | 339,728 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 4,539,680 | 0 | 339,728 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 8,015,846 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 33,363 | 314,706 | 9,319 | 66,928 | 3,787 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 16,296,359 | 16,296,359 | 16,296,359 | 16,296,359 | 16,296,359 | 12,820,193 | 12,820,193 | 13,159,921 | 13,159,921 | 13,159,921 | 13,159,921 | 13,159,921 | 13,159,921 | |
| 3 | Less: Accumulated Depreciation © | (5,199,196) | (5,218,796) | (4,957,053) | (5,000,697) | (4,986,732) | 2,985,586 | 2,943,920 | 2,901,702 | 2,858,932 | 2,816,162 | 2,773,392 | 2,730,622 | 2,687,852 | |
| 4 | CWIP - Non Interest Bearing | 1,465,138 | 1,760,531 | 2,127,107 | 4,341,513 | 4,416,999 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 12,562,301 | 12,838,094 | 13,466,413 | 15,637,175 | 15,726,626 | 15,805,779 | 15,764,113 | 16,061,623 | 16,018,853 | 15,976,083 | 15,933,313 | 15,890,543 | 15,847,773 | |
| 6 | Average Net Investment | | 12,700,198 | 13,152,254 | 14,551,794 | 15,681,901 | 15,766,203 | 15,784,946 | 15,912,868 | 16,040,238 | 15,997,468 | 15,954,698 | 15,911,928 | 15,869,158 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 93,308 | 96,630 | 106,912 | 115,215 | 115,834 | 115,972 | 116,912 | 117,848 | 117,533 | 117,219 | 116,905 | 116,591 | 1,346,879 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 26,505 | 27,449 | 30,370 | 32,728 | 32,904 | 32,943 | 33,210 | 33,476 | 33,387 | 33,297 | 33,208 | 33,119 | 382,596 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 52,963 | 52,963 | 52,963 | 52,963 | 47,315 | 41,666 | 42,218 | 42,770 | 42,770 | 42,770 | 42,770 | 42,770 | 556,901 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 172,776 | 177,042 | 190,245 | 200,906 | 196,053 | 190,581 | 192,340 | 194,094 | 193,690 | 193,286 | 192,883 | 192,480 | 2,286,376 |
| | a Recoverable Costs Allocated to Energy | | 172,776 | 177,042 | 190,245 | 200,906 | 196,053 | 190,581 | 192,340 | 194,094 | 193,690 | 193,286 | 192,883 | 192,480 | 2,286,376 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 166,895 | 171,167 | 184,417 | 194,726 | 190,074 | 184,754 | 186,131 | 187,839 | 187,125 | 186,754 | 185,850 | 185,623 | 2,211,355 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 166,895 | 171,167 | 184,417 | 194,726 | 190,074 | 184,754 | 186,131 | 187,839 | 187,125 | 186,754 | 185,850 | 185,623 | 2,211,355 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Crist, Scholz, Smith, & Daniel
P.E.s 1154, 1164, 1240, 1245, 1286, 1289, 1290, 1311, 1316, 1323, 1330, 1440, 1441, 1442, 1454, 1459, 1460 & 1558
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 80,000 | 77,000 | 58,300 | 100,300 | 58,400 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 157,000 | 0 | 217,000 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 32,500 | 0 | 0 | 100,000 | 0 | 200,000 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5,000 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 3,938,342 | 3,938,342 | 3,938,342 | 3,938,342 | 3,938,342 | 3,938,342 | 3,938,342 | 3,905,842 | 3,905,842 | 3,905,842 | 3,962,842 | 3,962,842 | 3,979,842 | |
| 3 | Less: Accumulated Depreciation © | 1,063,633 | 1,052,101 | 1,040,569 | 1,029,037 | 1,017,505 | 1,005,973 | 994,441 | 1,015,447 | 1,003,991 | 992,535 | 1,085,987 | 1,074,346 | 1,262,697 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 80,000 | 157,000 | 58,300 | 158,600 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 5,001,975 | 4,990,443 | 4,978,911 | 4,967,379 | 4,955,847 | 4,944,315 | 4,932,783 | 4,921,289 | 4,989,833 | 5,055,377 | 5,107,129 | 5,195,788 | 5,242,539 | |
| 6 | Average Net Investment | | 4,996,209 | 4,984,677 | 4,973,145 | 4,961,613 | 4,950,081 | 4,938,549 | 4,927,036 | 4,955,561 | 5,022,605 | 5,081,253 | 5,151,459 | 5,219,164 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 36,707 | 36,622 | 36,538 | 36,453 | 36,368 | 36,284 | 36,199 | 36,409 | 36,901 | 37,332 | 37,848 | 38,345 | 442,006 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 10,427 | 10,403 | 10,379 | 10,355 | 10,331 | 10,307 | 10,283 | 10,342 | 10,482 | 10,605 | 10,751 | 10,892 | 125,557 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 11,532 | 11,532 | 11,532 | 11,532 | 11,532 | 11,532 | 11,494 | 11,456 | 11,456 | 11,548 | 11,641 | 11,649 | 138,436 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 1,274 | 1,274 | 1,274 | 1,274 | 1,274 | 1,274 | 1,274 | 1,274 | 1,274 | 1,274 | 1,274 | 1,274 | 15,288 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 59,940 | 59,831 | 59,723 | 59,614 | 59,505 | 59,397 | 59,250 | 59,481 | 60,113 | 60,759 | 61,514 | 62,160 | 721,287 |
| | a Recoverable Costs Allocated to Energy | | 59,940 | 59,831 | 59,723 | 59,614 | 59,505 | 59,397 | 59,250 | 59,481 | 60,113 | 60,759 | 61,514 | 62,160 | 721,287 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 57,900 | 57,846 | 57,893 | 57,780 | 57,690 | 57,581 | 57,337 | 57,564 | 58,075 | 58,706 | 59,271 | 59,945 | 697,588 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 57,900 | 57,846 | 57,893 | 57,780 | 57,690 | 57,581 | 57,337 | 57,564 | 58,075 | 58,706 | 59,271 | 59,945 | 697,588 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $2,200,037; Scholz $486,600; Smith $565,863; Daniel $565,863. Ending Balances: Crist, $2,232,037; Scholz $486,600; Smith $685,842; Daniel $575,363
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) Crist: 3.9%; Smith 3.3%; Scholz 2.9%; Daniel 2.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Sub. Contam. Mobile Groundwater Treat. Sys.
P.E. 1007, 3400, & 3412
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | |
| 3 | Less: Accumulated Depreciation © | (100,707) | (102,754) | (104,801) | (106,848) | (108,895) | (110,942) | (112,989) | (115,036) | (117,083) | (119,130) | (121,177) | (123,224) | (125,270) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 828,687 | 826,640 | 824,593 | 822,546 | 820,499 | 818,452 | 816,405 | 814,358 | 812,311 | 810,264 | 808,217 | 806,170 | 804,124 | |
| 6 | Average Net Investment | | 827,664 | 825,617 | 823,570 | 821,523 | 819,476 | 817,429 | 815,382 | 813,335 | 811,288 | 809,241 | 807,194 | 805,148 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 6,081 | 6,066 | 6,051 | 6,036 | 6,021 | 6,006 | 5,991 | 5,976 | 5,961 | 5,945 | 5,930 | 5,915 | 71,979 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 1,727 | 1,723 | 1,719 | 1,715 | 1,710 | 1,706 | 1,702 | 1,697 | 1,693 | 1,689 | 1,685 | 1,680 | 20,446 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,911 | 22,943 |
| | b Amortization (F) | | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 1,620 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 9,855 | 9,835 | 9,817 | 9,798 | 9,779 | 9,759 | 9,739 | 9,720 | 9,701 | 9,682 | 9,663 | 9,641 | 116,988 |
| | a Recoverable Costs Allocated to Energy | | 759 | 756 | 755 | 754 | 752 | 751 | 749 | 747 | 746 | 745 | 744 | 742 | 9,000 |
| | b Recoverable Costs Allocated to Demand | | 9,096 | 9,079 | 9,062 | 9,044 | 9,027 | 9,008 | 8,990 | 8,973 | 8,955 | 8,937 | 8,919 | 8,899 | 107,989 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 733 | 731 | 732 | 731 | 729 | 728 | 725 | 723 | 721 | 720 | 717 | 716 | 8,706 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 8,778 | 8,761 | 8,745 | 8,728 | 8,711 | 8,693 | 8,676 | 8,659 | 8,642 | 8,624 | 8,607 | 8,588 | 104,212 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 9,511 | 9,492 | 9,477 | 9,459 | 9,440 | 9,421 | 9,401 | 9,382 | 9,363 | 9,344 | 9,324 | 9,304 | 112,918 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and ending balance for depreciable property: $131,648
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) Part of PE 1007 depreciable at 2.5% annually, PEs 3400 and 3412 depreciable at 2.5% annually
(F) 7 year amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith
P.E. 1155 & 1606
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | |
| 3 | Less: Accumulated Depreciation © | (22,290) | (23,033) | (23,776) | (24,519) | (25,262) | (26,005) | (26,748) | (27,491) | (28,234) | (28,977) | (29,721) | (30,465) | (31,209) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 220,653 | 219,910 | 219,167 | 218,424 | 217,681 | 216,938 | 216,195 | 215,452 | 214,709 | 213,966 | 213,222 | 212,478 | 211,734 | |
| 6 | Average Net Investment | | 220,282 | 219,539 | 218,796 | 218,053 | 217,310 | 216,567 | 215,824 | 215,081 | 214,338 | 213,594 | 212,850 | 212,106 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 1,618 | 1,613 | 1,607 | 1,602 | 1,597 | 1,591 | 1,586 | 1,580 | 1,575 | 1,569 | 1,564 | 1,558 | 19,060 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 460 | 458 | 457 | 455 | 454 | 452 | 450 | 449 | 447 | 446 | 444 | 443 | 5,415 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 743 | 743 | 743 | 743 | 743 | 743 | 743 | 743 | 743 | 744 | 744 | 744 | 8,919 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 2,820 | 2,814 | 2,807 | 2,800 | 2,793 | 2,786 | 2,779 | 2,772 | 2,765 | 2,759 | 2,751 | 2,746 | 33,394 |
| | a Recoverable Costs Allocated to Energy | | 217 | 216 | 216 | 216 | 215 | 214 | 214 | 213 | 213 | 213 | 211 | 211 | 2,569 |
| | b Recoverable Costs Allocated to Demand | | 2,603 | 2,598 | 2,591 | 2,584 | 2,578 | 2,572 | 2,565 | 2,559 | 2,552 | 2,546 | 2,540 | 2,535 | 30,823 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 210 | 209 | 209 | 209 | 208 | 207 | 207 | 206 | 206 | 206 | 203 | 203 | 2,483 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,512 | 2,507 | 2,500 | 2,494 | 2,488 | 2,482 | 2,475 | 2,469 | 2,463 | 2,457 | 2,451 | 2,446 | 29,744 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 2,722 | 2,716 | 2,709 | 2,703 | 2,696 | 2,689 | 2,682 | 2,675 | 2,669 | 2,663 | 2,654 | 2,649 | 32,227 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,920 and Smith $93,023
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.9%; Smith 3.3% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | |
| 3 | Less: Accumulated Depreciation © | (335,771) | (338,923) | (342,074) | (345,226) | (348,377) | (351,528) | (354,679) | (357,831) | (360,983) | (364,134) | (367,286) | (370,436) | (373,587) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 570,888 | 567,736 | 564,585 | 561,433 | 558,282 | 555,131 | 551,980 | 548,828 | 545,676 | 542,525 | 539,373 | 536,223 | 533,072 | |
| 6 | Average Net Investment | | 569,312 | 566,161 | 563,009 | 559,858 | 556,707 | 553,556 | 550,404 | 547,252 | 544,101 | 540,949 | 537,798 | 534,648 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 4,183 | 4,160 | 4,136 | 4,113 | 4,090 | 4,067 | 4,044 | 4,021 | 3,998 | 3,974 | 3,951 | 3,928 | 48,665 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 1,188 | 1,182 | 1,175 | 1,168 | 1,162 | 1,155 | 1,149 | 1,142 | 1,136 | 1,129 | 1,122 | 1,116 | 13,824 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,946 | 2,947 | 35,363 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 205 | 204 | 205 | 204 | 204 | 204 | 205 | 205 | 204 | 205 | 204 | 204 | 2,453 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 8,523 | 8,493 | 8,463 | 8,432 | 8,403 | 8,373 | 8,345 | 8,315 | 8,285 | 8,255 | 8,223 | 8,195 | 100,305 |
| | a Recoverable Costs Allocated to Energy | | 656 | 653 | 651 | 649 | 646 | 644 | 642 | 640 | 637 | 635 | 633 | 630 | 7,716 |
| | b Recoverable Costs Allocated to Demand | | 7,867 | 7,840 | 7,812 | 7,783 | 7,757 | 7,729 | 7,703 | 7,675 | 7,648 | 7,620 | 7,590 | 7,565 | 92,589 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 634 | 631 | 631 | 629 | 626 | 624 | 621 | 619 | 615 | 614 | 610 | 608 | 7,462 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 7,592 | 7,566 | 7,539 | 7,511 | 7,486 | 7,459 | 7,434 | 7,407 | 7,380 | 7,353 | 7,324 | 7,300 | 89,351 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 8,226 | 8,197 | 8,170 | 8,140 | 8,112 | 8,083 | 8,055 | 8,026 | 7,995 | 7,967 | 7,934 | 7,908 | 96,813 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 1-5 Dechlorination
P.E. 1248
(in Dollars)

| Line | Description | Beginning of Period Amoun | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | |
| 3 | Less: Accumulated Depreciation © | (90,897) | (91,889) | (92,881) | (93,873) | (94,865) | (95,857) | (96,849) | (97,841) | (98,833) | (99,825) | (100,817) | (101,809) | (102,801) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 214,426 | 213,434 | 212,442 | 211,450 | 210,458 | 209,466 | 208,474 | 207,482 | 206,490 | 205,498 | 204,506 | 203,514 | 202,522 | |
| 6 | Average Net Investment | | 213,930 | 212,938 | 211,946 | 210,954 | 209,962 | 208,970 | 207,978 | 206,986 | 205,994 | 205,002 | 204,010 | 203,018 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 1,572 | 1,564 | 1,557 | 1,550 | 1,543 | 1,535 | 1,528 | 1,521 | 1,513 | 1,506 | 1,499 | 1,492 | 18,380 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 446 | 444 | 442 | 440 | 438 | 436 | 434 | 432 | 430 | 428 | 426 | 424 | 5,220 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 992 | 992 | 992 | 992 | 992 | 992 | 992 | 992 | 992 | 992 | 992 | 992 | 11,904 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 3,010 | 3,000 | 2,991 | 2,982 | 2,973 | 2,963 | 2,954 | 2,945 | 2,935 | 2,926 | 2,917 | 2,908 | 35,504 |
| | a Recoverable Costs Allocated to Energy | | 232 | 231 | 230 | 229 | 229 | 228 | 227 | 227 | 226 | 225 | 224 | 224 | 2,732 |
| | b Recoverable Costs Allocated to Demand | | 2,778 | 2,769 | 2,761 | 2,753 | 2,744 | 2,735 | 2,727 | 2,718 | 2,709 | 2,701 | 2,693 | 2,684 | 32,772 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 224 | 223 | 223 | 222 | 222 | 221 | 220 | 220 | 218 | 217 | 216 | 216 | 2,642 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,681 | 2,672 | 2,664 | 2,657 | 2,648 | 2,639 | 2,632 | 2,623 | 2,614 | 2,607 | 2,599 | 2,590 | 31,626 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 2,905 | 2,895 | 2,887 | 2,879 | 2,870 | 2,860 | 2,852 | 2,843 | 2,832 | 2,824 | 2,815 | 2,806 | 34,268 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5,000 | 5,000 | 5,000 | 5,000 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20,000 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 47,955 | 67,955 | |
| 3 | Less: Accumulated Depreciation © | (14,937) | (15,093) | (15,249) | (15,405) | (15,561) | (15,717) | (15,873) | (16,029) | (16,185) | (16,341) | (16,497) | (16,653) | (16,841) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5,000 | 10,000 | 15,000 | 20,000 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 33,018 | 32,862 | 32,706 | 32,550 | 32,394 | 32,238 | 32,082 | 31,926 | 36,770 | 41,614 | 46,458 | 51,302 | 51,114 | |
| 6 | Average Net Investment | | 32,940 | 32,784 | 32,628 | 32,472 | 32,316 | 32,160 | 32,004 | 34,348 | 39,192 | 44,036 | 48,880 | 51,208 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 242 | 241 | 240 | 239 | 237 | 236 | 235 | 252 | 288 | 324 | 359 | 376 | 3,269 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 69 | 68 | 68 | 68 | 67 | 67 | 67 | 72 | 82 | 92 | 102 | 107 | 929 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 156 | 188 | 1,904 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 467 | 465 | 464 | 463 | 460 | 459 | 458 | 480 | 526 | 572 | 617 | 671 | 6,102 |
| | a Recoverable Costs Allocated to Energy | | 36 | 36 | 36 | 36 | 35 | 35 | 35 | 37 | 40 | 44 | 47 | 52 | 469 |
| | b Recoverable Costs Allocated to Demand | | 431 | 429 | 428 | 427 | 425 | 424 | 423 | 443 | 486 | 528 | 570 | 619 | 5,633 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 35 | 35 | 35 | 35 | 34 | 34 | 34 | 36 | 39 | 43 | 45 | 50 | 455 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 416 | 414 | 413 | 412 | 410 | 409 | 408 | 428 | 469 | 510 | 550 | 597 | 5,436 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 451 | 449 | 448 | 447 | 444 | 443 | 442 | 464 | 508 | 553 | 595 | 647 | 5,891 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unload Sec Contain Struc
P.E. 1271
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | |
| 3 | Less: Accumulated Depreciation © | (30,152) | (30,482) | (30,812) | (31,142) | (31,472) | (31,802) | (32,132) | (32,462) | (32,792) | (33,122) | (33,452) | (33,782) | (34,112) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 71,343 | 71,013 | 70,683 | 70,353 | 70,023 | 69,693 | 69,363 | 69,033 | 68,703 | 68,373 | 68,043 | 67,713 | 67,383 | |
| 6 | Average Net Investment | | 71,178 | 70,848 | 70,518 | 70,188 | 69,858 | 69,528 | 69,198 | 68,868 | 68,538 | 68,208 | 67,878 | 67,548 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 523 | 521 | 518 | 516 | 513 | 511 | 508 | 506 | 504 | 501 | 499 | 496 | 6,116 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 149 | 148 | 147 | 146 | 146 | 145 | 144 | 144 | 143 | 142 | 142 | 141 | 1,737 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 3,960 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 1,002 | 999 | 995 | 992 | 989 | 986 | 982 | 980 | 977 | 973 | 971 | 967 | 11,813 |
| | a Recoverable Costs Allocated to Energy | | 77 | 77 | 77 | 76 | 76 | 76 | 76 | 75 | 75 | 75 | 75 | 74 | 909 |
| | b Recoverable Costs Allocated to Demand | | 925 | 922 | 918 | 916 | 913 | 910 | 906 | 905 | 902 | 898 | 896 | 893 | 10,904 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 74 | 74 | 75 | 74 | 74 | 74 | 74 | 73 | 72 | 72 | 72 | 71 | 879 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 893 | 890 | 886 | 884 | 881 | 878 | 874 | 873 | 870 | 867 | 865 | 862 | 10,523 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 967 | 964 | 961 | 958 | 955 | 952 | 948 | 946 | 942 | 939 | 937 | 933 | 11,402 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
**January 2004 - December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | |
| 3 | Less: Accumulated Depreciation © | (18,006) | (18,200) | (18,394) | (18,588) | (18,782) | (18,976) | (19,170) | (19,364) | (19,558) | (19,752) | (19,946) | (20,140) | (20,334) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 41,537 | 41,343 | 41,149 | 40,955 | 40,761 | 40,567 | 40,373 | 40,179 | 39,985 | 39,791 | 39,597 | 39,403 | 39,209 | |
| 6 | Average Net Investment | | 41,440 | 41,246 | 41,052 | 40,858 | 40,664 | 40,470 | 40,276 | 40,082 | 39,888 | 39,694 | 39,500 | 39,306 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 304 | 303 | 302 | 300 | 299 | 297 | 296 | 294 | 293 | 292 | 290 | 289 | 3,559 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 86 | 86 | 86 | 85 | 85 | 84 | 84 | 84 | 83 | 83 | 82 | 82 | 1,010 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 2,328 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 584 | 583 | 582 | 579 | 578 | 575 | 574 | 572 | 570 | 569 | 566 | 565 | 6,897 |
| | a Recoverable Costs Allocated to Energy | | 45 | 45 | 45 | 45 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 43 | 531 |
| | b Recoverable Costs Allocated to Demand | | 539 | 538 | 537 | 534 | 534 | 531 | 530 | 528 | 526 | 525 | 522 | 522 | 6,366 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 43 | 44 | 44 | 44 | 43 | 43 | 43 | 43 | 43 | 43 | 42 | 41 | 516 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 520 | 519 | 518 | 515 | 515 | 512 | 511 | 510 | 508 | 507 | 504 | 504 | 6,143 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 563 | 563 | 562 | 559 | 558 | 555 | 554 | 553 | 551 | 550 | 546 | 545 | 6,659 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Sodium Injection System
P.E. 1413
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | |
| 3 | Less: Accumulated Depreciation © | (13,988) | (14,281) | (14,574) | (14,867) | (15,160) | (15,453) | (15,746) | (16,039) | (16,332) | (16,625) | (16,918) | (17,211) | (17,504) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 92,509 | 92,216 | 91,923 | 91,630 | 91,337 | 91,044 | 90,751 | 90,458 | 90,165 | 89,872 | 89,579 | 89,286 | 88,993 | |
| 6 | Average Net Investment | | 92,363 | 92,070 | 91,777 | 91,484 | 91,191 | 90,898 | 90,605 | 90,312 | 90,019 | 89,726 | 89,433 | 89,140 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 679 | 676 | 674 | 672 | 670 | 668 | 666 | 664 | 661 | 659 | 657 | 655 | 8,001 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 193 | 192 | 192 | 191 | 190 | 190 | 189 | 188 | 188 | 187 | 187 | 186 | 2,273 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 3,516 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 1,165 | 1,161 | 1,159 | 1,156 | 1,153 | 1,151 | 1,148 | 1,145 | 1,142 | 1,139 | 1,137 | 1,134 | 13,790 |
| | a Recoverable Costs Allocated to Energy | | 1,165 | 1,161 | 1,159 | 1,156 | 1,153 | 1,151 | 1,148 | 1,145 | 1,142 | 1,139 | 1,137 | 1,134 | 13,790 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 1,125 | 1,122 | 1,123 | 1,120 | 1,118 | 1,116 | 1,111 | 1,108 | 1,103 | 1,101 | 1,096 | 1,094 | 13,337 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 1,125 | 1,122 | 1,123 | 1,120 | 1,118 | 1,116 | 1,111 | 1,108 | 1,103 | 1,101 | 1,096 | 1,094 | 13,337 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
**January 2004 - December 2004**

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | |
| 3 | Less: Accumulated Depreciation © | (711,786) | (719,438) | (727,090) | (734,742) | (742,394) | (750,046) | (757,698) | (765,350) | (773,002) | (780,654) | (788,306) | (795,958) | (803,610) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 2,070,814 | 2,063,162 | 2,055,510 | 2,047,858 | 2,040,206 | 2,032,554 | 2,024,902 | 2,017,250 | 2,009,598 | 2,001,946 | 1,994,294 | 1,986,642 | 1,978,990 | |
| 6 | Average Net Investment | | 2,066,988 | 2,059,336 | 2,051,684 | 2,044,032 | 2,036,380 | 2,028,728 | 2,021,076 | 2,013,424 | 2,005,772 | 1,998,120 | 1,990,468 | 1,982,816 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 15,186 | 15,130 | 15,074 | 15,018 | 14,961 | 14,905 | 14,849 | 14,793 | 14,736 | 14,680 | 14,624 | 14,568 | 178,524 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 4,314 | 4,298 | 4,282 | 4,266 | 4,250 | 4,234 | 4,218 | 4,202 | 4,186 | 4,170 | 4,154 | 4,138 | 50,712 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 91,824 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 27,152 | 27,080 | 27,008 | 26,936 | 26,863 | 26,791 | 26,719 | 26,647 | 26,574 | 26,502 | 26,430 | 26,358 | 321,060 |
| | a Recoverable Costs Allocated to Energy | | 2,089 | 2,083 | 2,078 | 2,072 | 2,066 | 2,061 | 2,055 | 2,050 | 2,044 | 2,039 | 2,033 | 2,028 | 24,698 |
| | b Recoverable Costs Allocated to Demand | | 25,063 | 24,997 | 24,930 | 24,864 | 24,797 | 24,730 | 24,664 | 24,597 | 24,530 | 24,463 | 24,397 | 24,330 | 296,362 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 2,018 | 2,014 | 2,014 | 2,008 | 2,003 | 1,998 | 1,989 | 1,984 | 1,975 | 1,970 | 1,959 | 1,956 | 23,888 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 24,186 | 24,123 | 24,058 | 23,994 | 23,930 | 23,865 | 23,801 | 23,737 | 23,672 | 23,607 | 23,544 | 23,479 | 285,996 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 26,204 | 26,137 | 26,072 | 26,002 | 25,933 | 25,863 | 25,790 | 25,721 | 25,647 | 25,577 | 25,503 | 25,435 | 309,884 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water
P.E. 1466 & 1643
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 14,983 | 0 | 5,000 | 5,000 | 35,000 | 91,438 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 151,421 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 105,795 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 175,200 | 220,826 | 220,826 | 220,826 | |
| 3 | Less: Accumulated Depreciation © | (50,245) | (50,727) | (51,209) | (51,691) | (52,173) | (52,655) | (53,137) | (53,619) | (54,101) | (54,583) | 50,667 | 50,060 | 49,453 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 14,983 | 14,983 | 19,983 | 24,983 | 59,983 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 124,955 | 124,473 | 123,991 | 123,509 | 123,027 | 137,528 | 137,046 | 141,564 | 146,082 | 180,600 | 271,493 | 270,886 | 270,279 | |
| 6 | Average Net Investment | | 124,714 | 124,232 | 123,750 | 123,268 | 130,278 | 137,287 | 139,305 | 143,823 | 163,341 | 226,047 | 271,190 | 270,583 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 916 | 913 | 909 | 906 | 957 | 1,009 | 1,023 | 1,057 | 1,200 | 1,661 | 1,992 | 1,988 | 14,531 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 260 | 259 | 258 | 257 | 272 | 287 | 291 | 300 | 341 | 472 | 566 | 565 | 4,128 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 482 | 482 | 482 | 482 | 482 | 482 | 482 | 482 | 482 | 545 | 607 | 607 | 6,097 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 1,658 | 1,654 | 1,649 | 1,645 | 1,711 | 1,777 | 1,795 | 1,838 | 2,023 | 2,677 | 3,166 | 3,159 | 24,756 |
| | a Recoverable Costs Allocated to Energy | | 128 | 127 | 127 | 127 | 131 | 137 | 138 | 141 | 156 | 206 | 243 | 243 | 1,904 |
| | b Recoverable Costs Allocated to Demand | | 1,530 | 1,527 | 1,522 | 1,518 | 1,580 | 1,640 | 1,657 | 1,697 | 1,867 | 2,471 | 2,923 | 2,916 | 22,848 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 124 | 123 | 123 | 123 | 127 | 133 | 134 | 136 | 151 | 199 | 234 | 234 | 1,841 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 1,476 | 1,474 | 1,469 | 1,465 | 1,525 | 1,583 | 1,599 | 1,638 | 1,802 | 2,385 | 2,821 | 2,814 | 22,051 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 1,600 | 1,597 | 1,592 | 1,588 | 1,652 | 1,716 | 1,733 | 1,774 | 1,953 | 2,584 | 3,055 | 3,048 | 23,892 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) Smith 3.3% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E. 1535
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | 13,242,469 | |
| 3 | Less: Accumulated Depreciation © | (3,817,679) | (3,858,397) | (3,899,115) | (3,939,833) | (3,980,551) | (4,021,269) | (4,061,987) | (4,102,705) | (4,143,423) | (4,184,141) | (4,224,859) | (4,265,577) | (4,306,295) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 9,424,790 | 9,384,072 | 9,343,354 | 9,302,636 | 9,261,918 | 9,221,200 | 9,180,482 | 9,139,764 | 9,099,046 | 9,058,328 | 9,017,610 | 8,976,892 | 8,936,174 | |
| 6 | Average Net Investment | | 9,404,431 | 9,363,713 | 9,322,995 | 9,282,277 | 9,241,559 | 9,200,841 | 9,160,123 | 9,119,405 | 9,078,687 | 9,037,969 | 8,997,251 | 8,956,533 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 69,094 | 68,795 | 68,496 | 68,197 | 67,898 | 67,599 | 67,299 | 67,000 | 66,701 | 66,402 | 66,103 | 65,804 | 809,388 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 19,627 | 19,542 | 19,457 | 19,372 | 19,287 | 19,202 | 19,117 | 19,032 | 18,947 | 18,862 | 18,777 | 18,692 | 229,914 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 30,895 | 370,740 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 117,876 |
| | d Property Taxes | | 27,339 | 27,339 | 27,339 | 27,339 | 27,339 | 27,339 | 27,339 | 27,339 | 27,339 | 27,339 | 27,339 | 27,339 | 328,068 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 156,778 | 156,394 | 156,010 | 155,626 | 155,242 | 154,858 | 154,473 | 154,089 | 153,705 | 153,321 | 152,937 | 152,553 | 1,855,986 |
| | a Recoverable Costs Allocated to Energy | | 12,060 | 12,030 | 12,001 | 11,971 | 11,942 | 11,912 | 11,883 | 11,853 | 11,823 | 11,794 | 11,764 | 11,735 | 142,768 |
| | b Recoverable Costs Allocated to Demand | | 144,718 | 144,364 | 144,009 | 143,655 | 143,300 | 142,946 | 142,590 | 142,236 | 141,882 | 141,527 | 141,173 | 140,818 | 1,713,218 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 11,650 | 11,631 | 11,633 | 11,603 | 11,578 | 11,548 | 11,499 | 11,471 | 11,422 | 11,395 | 11,335 | 11,317 | 138,082 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 139,656 | 139,314 | 138,971 | 138,630 | 138,287 | 137,946 | 137,602 | 137,260 | 136,919 | 136,576 | 136,235 | 135,892 | 1,653,288 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 151,306 | 150,945 | 150,604 | 150,233 | 149,865 | 149,494 | 149,101 | 148,731 | 148,341 | 147,971 | 147,570 | 147,209 | 1,791,370 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 2.8% annually
(F) 0
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Shield Water Project
P.E. 1620
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | 47,906 | |
| 3 | Less: Accumulated Depreciation © | (3,359) | (3,491) | (3,623) | (3,755) | (3,887) | (4,019) | (4,151) | (4,283) | (4,415) | (4,547) | (4,679) | (4,811) | (4,943) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 44,547 | 44,415 | 44,283 | 44,151 | 44,019 | 43,887 | 43,755 | 43,623 | 43,491 | 43,359 | 43,227 | 43,095 | 42,963 | |
| 6 | Average Net Investment | | 44,481 | 44,349 | 44,217 | 44,085 | 43,953 | 43,821 | 43,689 | 43,557 | 43,425 | 43,293 | 43,161 | 43,029 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 327 | 326 | 325 | 324 | 323 | 322 | 321 | 320 | 319 | 318 | 317 | 316 | 3,858 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 93 | 93 | 92 | 92 | 92 | 91 | 91 | 91 | 91 | 90 | 90 | 90 | 1,096 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 1,584 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 552 | 551 | 549 | 548 | 547 | 545 | 544 | 543 | 542 | 540 | 539 | 538 | 6,538 |
| | a Recoverable Costs Allocated to Energy | | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 41 | 41 | 502 |
| | b Recoverable Costs Allocated to Demand | | 510 | 509 | 507 | 506 | 505 | 503 | 502 | 501 | 500 | 498 | 498 | 497 | 6,036 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 40 | 40 | 490 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 492 | 491 | 489 | 488 | 487 | 485 | 484 | 483 | 483 | 481 | 481 | 480 | 5,824 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 533 | 532 | 530 | 529 | 528 | 526 | 525 | 524 | 524 | 522 | 521 | 520 | 6,314 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | |
| 3 | Less: Accumulated Depreciation © | (398,875) | (403,796) | (408,716) | (413,637) | (418,558) | (423,478) | (428,399) | (433,319) | (438,240) | (443,160) | (448,081) | (453,001) | (457,921) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 59,044 | 54,123 | 49,203 | 44,282 | 39,361 | 34,441 | 29,520 | 24,600 | 19,679 | 14,759 | 9,838 | 4,918 | (2) | |
| 6 | Average Net Investment | | 56,584 | 51,663 | 46,743 | 41,822 | 36,901 | 31,981 | 27,060 | 22,140 | 17,219 | 12,299 | 7,378 | 2,458 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 416 | 380 | 343 | 307 | 271 | 235 | 199 | 163 | 127 | 90 | 54 | 18 | 2,603 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 118 | 108 | 98 | 87 | 77 | 67 | 56 | 46 | 36 | 26 | 15 | 5 | 739 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b Amortization (F) | | 4,921 | 4,920 | 4,921 | 4,921 | 4,920 | 4,921 | 4,920 | 4,921 | 4,920 | 4,921 | 4,920 | 4,920 | 59,046 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 5,455 | 5,408 | 5,362 | 5,315 | 5,268 | 5,223 | 5,175 | 5,130 | 5,083 | 5,037 | 4,989 | 4,943 | 62,388 |
| | a Recoverable Costs Allocated to Energy | | 420 | 416 | 412 | 409 | 405 | 402 | 398 | 395 | 391 | 387 | 384 | 380 | 4,799 |
| | b Recoverable Costs Allocated to Demand | | 5,035 | 4,992 | 4,950 | 4,906 | 4,863 | 4,821 | 4,777 | 4,735 | 4,692 | 4,650 | 4,605 | 4,563 | 57,589 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 406 | 402 | 399 | 396 | 393 | 390 | 385 | 382 | 378 | 374 | 370 | 366 | 4,641 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 4,859 | 4,817 | 4,777 | 4,734 | 4,693 | 4,652 | 4,610 | 4,569 | 4,528 | 4,487 | 4,444 | 4,403 | 55,573 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 5,265 | 5,219 | 5,176 | 5,130 | 5,086 | 5,042 | 4,995 | 4,951 | 4,906 | 4,861 | 4,814 | 4,769 | 60,214 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) 7 year amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E. 1199
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 919,642 | (55,051) | 23 | 35,796,346 | 1,223,707 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 227,262 | 1,146,904 | 1,091,853 | 1,091,876 | 36,888,222 | 38,111,929 | 38,111,929 | 38,111,929 | 38,111,929 | 38,111,929 | 38,111,929 | 38,111,929 | 38,111,929 | |
| 3 | Less: Accumulated Depreciation © | (369) | (2,602) | (6,240) | (9,789) | (71,507) | (193,382) | (317,246) | (441,110) | (564,974) | (688,838) | (812,702) | (936,566) | (1,060,430) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 226,893 | 1,144,302 | 1,085,613 | 1,082,087 | 36,816,715 | 37,918,547 | 37,794,683 | 37,670,819 | 37,546,955 | 37,423,091 | 37,299,227 | 37,175,363 | 37,051,499 | |
| 6 | Average Net Investment | | 685,598 | 1,114,958 | 1,083,850 | 18,949,401 | 37,367,631 | 37,856,615 | 37,732,751 | 37,608,887 | 37,485,023 | 37,361,159 | 37,237,295 | 37,113,431 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 5,037 | 8,192 | 7,963 | 139,221 | 274,540 | 278,133 | 277,223 | 276,312 | 275,402 | 274,492 | 273,582 | 272,672 | 2,362,769 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 1,431 | 2,327 | 2,262 | 39,547 | 77,986 | 79,007 | 78,748 | 78,490 | 78,231 | 77,973 | 77,714 | 77,456 | 671,172 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 2,233 | 3,638 | 3,549 | 61,718 | 121,875 | 123,864 | 123,864 | 123,864 | 123,864 | 123,864 | 123,864 | 123,864 | 1,060,061 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 8,701 | 14,157 | 13,774 | 240,486 | 474,401 | 481,004 | 479,835 | 478,666 | 477,497 | 476,329 | 475,160 | 473,992 | 4,094,002 |
| | a Recoverable Costs Allocated to Energy | | 8,701 | 14,157 | 13,774 | 240,486 | 474,401 | 481,004 | 479,835 | 478,666 | 477,497 | 476,329 | 475,160 | 473,992 | 4,094,002 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 8,405 | 13,687 | 13,352 | 233,088 | 459,933 | 466,298 | 464,344 | 463,240 | 461,312 | 460,232 | 457,835 | 457,105 | 3,958,831 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 8,405 | 13,687 | 13,352 | 233,088 | 459,933 | 466,298 | 464,344 | 463,240 | 461,312 | 460,232 | 457,835 | 457,105 | 3,958,831 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) Crist: 3.9%
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Switchyard Stormwater
P.E. 1272
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 82 | 0 | 41,593 | 41,675 | 41,675 | 41,675 | 41,675 | 41,625 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 250,000 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 250,000 | |
| 3 | Less: Accumulated Depreciation © | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (406) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 82 | 82 | 41,675 | 83,350 | 125,025 | 166,700 | 208,375 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 0 | 0 | 0 | 0 | 0 | 82 | 82 | 41,675 | 83,350 | 125,025 | 166,700 | 208,375 | 249,594 | |
| 6 | Average Net Investment | | 0 | 0 | 0 | 0 | 41 | 82 | 20,879 | 62,513 | 104,188 | 145,863 | 187,538 | 228,985 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 0 | 0 | 0 | 0 | 0 | 1 | 153 | 459 | 765 | 1,072 | 1,378 | 1,682 | 5,510 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 44 | 130 | 217 | 304 | 391 | 478 | 1,564 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 406 | 406 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 0 | 0 | 0 | 0 | 0 | 1 | 197 | 589 | 982 | 1,376 | 1,769 | 2,566 | 7,480 |
| | a Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 15 | 45 | 76 | 106 | 136 | 197 | 575 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 1 | 182 | 544 | 906 | 1,270 | 1,633 | 2,369 | 6,905 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 0 | 0 | 0 | 0 | 0 | 0 | 15 | 44 | 73 | 102 | 131 | 190 | 555 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 1 | 176 | 525 | 874 | 1,226 | 1,576 | 2,286 | 6,664 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 0 | 0 | 0 | 0 | 0 | 1 | 191 | 569 | 947 | 1,328 | 1,707 | 2,476 | 7,219 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 18,767 | 41,344 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 60,111 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 60,111 | 60,111 | 60,111 | 60,111 | |
| 3 | Less: Accumulated Depreciation © | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (98) | (293) | (488) | (683) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 18,767 | 60,111 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 18,767 | 60,111 | 60,013 | 59,818 | 59,623 | 59,428 | |
| 6 | Average Net Investment | | 0 | 0 | 0 | 0 | 0 | 0 | 9,384 | 39,439 | 60,062 | 59,916 | 59,721 | 59,526 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 69 | 290 | 441 | 440 | 439 | 437 | 2,116 |
| | b Debt Component (Line 6 x Debt Component x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 82 | 125 | 125 | 125 | 124 | 601 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 98 | 195 | 195 | 195 | 683 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 0 | 0 | 0 | 0 | 0 | 0 | 89 | 372 | 664 | 760 | 759 | 756 | 3,400 |
| | a Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 89 | 372 | 664 | 760 | 759 | 756 | 3,400 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 0 | 0 | 0 | 0 | 0 | 0 | 86 | 360 | 641 | 734 | 731 | 729 | 3,281 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | 0 | 0 | 0 | 0 | 0 | 0 | 86 | 360 | 641 | 734 | 731 | 729 | 3,281 |

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity compoent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
**January 2004 - December 2004**

Return on Working Capital, SO2 Expenses
For Project: SO2 Allowances

(in Dollars)

| Line | Description | Beginning of Period Amount | Actual January | Actual February | Actual March | Actual April | Actual May | Actual June | Estimated July | Estimated August | Estimated September | Estimated October | Estimated November | Estimated December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments | | | | | | | | | | | | | | |
| | a Purchases/Transfers | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Sales/Transfers | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Auction Proceeds/Other | | 0 | 0 | 0 | 0 | 356,476 | (34,157) | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Working Capital | | | | | | | | | | | | | | |
| | a FERC 158.1 Allowance Inventory | 19,941 | 19,217 | 18,585 | 17,903 | 17,444 | 16,667 | 15,971 | 14,889 | 13,806 | 12,779 | 11,899 | 11,043 | 10,174 | |
| | b FERC 158.2 Allowances Withheld | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c FERC 182.3 Other Regl. Assets - Losses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d FERC 254 Regulatory Liabilities - Gains | (662,537) | (654,841) | (647,145) | (639,449) | (631,753) | (950,183) | (877,980) | (839,935) | (801,890) | (763,845) | (725,799) | (687,753) | (649,707) | |
| 3 | Total Working Capital Balance | (642,596) | (635,624) | (628,560) | (621,546) | (614,309) | (933,516) | (862,009) | (825,046) | (788,084) | (751,066) | (713,900) | (676,710) | (639,533) | |
| 4 | Average Net Working Capital Balance | | (639,110) | (632,092) | (625,053) | (617,928) | (773,913) | (897,763) | (843,528) | (806,565) | (769,575) | (732,483) | (695,305) | (658,122) | |
| 5 | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (A) | | (4,696) | (4,644) | (4,592) | (4,540) | (5,686) | (6,596) | (6,197) | (5,926) | (5,654) | (5,382) | (5,108) | (4,835) | (63,856) |
| | b Debt Component (Line 4 x 3.5137% x 1/12) | | (1,334) | (1,319) | (1,304) | (1,290) | (1,615) | (1,874) | (1,760) | (1,683) | (1,606) | (1,529) | (1,451) | (1,374) | (18,139) |
| 6 | Total Return Component (D) | | (6,030) | (5,963) | (5,896) | (5,830) | (7,301) | (8,470) | (7,957) | (7,609) | (7,260) | (6,911) | (6,559) | (6,209) | (81,995) |
| 7 | Expenses | | | | | | | | | | | | | | |
| | a Gains | | (7,696) | (7,696) | (7,696) | (7,696) | (38,046) | (38,046) | (38,045) | (38,045) | (38,045) | (38,046) | (38,046) | (38,046) | (335,149) |
| | b Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c SO2 Allowance Expense | | 724 | 632 | 682 | 459 | 777 | 696 | 1,082 | 1,083 | 1,027 | 880 | 856 | 869 | 9,767 |
| 8 | Net Expenses (E) | | (6,972) | (7,064) | (7,014) | (7,237) | (37,269) | (37,350) | (36,963) | (36,962) | (37,018) | (37,166) | (37,190) | (37,177) | (325,382) |
| 9 | Total System Recoverable Expenses (Lines 6 + 7) | | (13,002) | (13,027) | (12,910) | (13,067) | (44,570) | (45,820) | (44,920) | (44,571) | (44,278) | (44,077) | (43,749) | (43,386) | (407,377) |
| | a Recoverable Costs Allocated to Energy | | (13,002) | (13,027) | (12,910) | (13,067) | (44,570) | (45,820) | (44,920) | (44,571) | (44,278) | (44,077) | (43,749) | (43,386) | (407,377) |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9652882 | 0.9661409 | 0.9686867 | 0.9685600 | 0.9688241 | 0.9687473 | 0.9670392 | 0.9670966 | 0.9654291 | 0.9655301 | 0.9628637 | 0.9636988 | |
| 11 | Demand Jurisdictional Factor | | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | 0.9650187 | |
| 12 | Retail Energy-Related Recoverable Costs (B) | | (12,559) | (12,595) | (12,514) | (12,665) | (43,211) | (44,419) | (43,470) | (43,135) | (42,777) | (42,587) | (42,154) | (41,840) | (393,926) |
| 13 | Retail Demand-Related Recoverable Costs (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Jurisdictional Recoverable Costs (Lines 12 + 13) | | (12,559) | (12,595) | (12,514) | (12,665) | (43,211) | (44,419) | (43,470) | (43,135) | (42,777) | (42,587) | (42,154) | (41,840) | (393,926) |

Notes:
(A) Line 4 x Equity Component x 1/12. Based on ROE of 12% and weighted income tax rate of 38.575%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Schedule 1P

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
**Total Jurisdictional Amount to be Recovered**

For the Projected Period
**January 2005 - December 2005**

| Line No. | | Energy ($) | Demand ($) | Total ($) |
|---|---|---|---|---|
| 1 | Total Jurisdictional Rev. Req. for the projected period | | | |
| | a Projected O & M Activities (Schedule 2P, Lines 7, 8 & 9) | 2,017,830 | 1,854,473 | 3,872,303 |
| | b Projected Capital Projects (Schedule 3P, Lines 7, 8 & 9) | 19,929,244 | 2,265,676 | 22,194,920 |
| | c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b) | 21,947,074 | 4,120,149 | 26,067,223 |
| 2 | True-Up for Estimated Over/(Under) Recovery for the period January 2004 - December 2004 (Schedule 1E, Line 4) | (83,715) | (29,936) | (113,651) |
| 3 | Final True-Up for the period January 2003 - December 2003 (Schedule 1A, Line 3) | 258,655 | 135,876 | 394,531 |
| 4 | Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2005 - December 2005 (Line 1c - Line 2 - Line 3) | 21,772,134 | 4,014,209 | 25,786,343 |
| 5 | Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier) | 21,787,810 | 4,017,099 | 25,804,909 |

Notes:
Allocation to energy and demand in each period are in proportion to the respective period split of costs indicated on Lines 7 & 8 of Schedules 5E & 7E and 5A & 7A.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI EXHIBIT NO. 17
COMPANY/ Gulf Power Co.
WITNESS: T. A. Davis (TAD-3)
DATE: 11-08-04

**Gulf Power Company**
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Schedule 2P**

**O & M Activities**
(in Dollars)

| Line | | January | February | March | April | May | June | July | August | September | October | November | December | End of Period 12-Month | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of O & M Activities | | | | | | | | | | | | | | | |
| | .1 Sulfur | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| | .2 Air Emission Fees | 0 | 655,500 | 0 | 0 | 0 | 0 | 0 | 124,374 | 0 | 0 | 0 | 0 | 779,874 | | 779,874 |
| | .3 Title V | 5,296 | 5,296 | 9,241 | 7,888 | 5,670 | 10,470 | 5,670 | 5,670 | 11,691 | 5,670 | 5,441 | 9,229 | 87,232 | | 87,232 |
| | .4 Asbestos Fees | 2,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,000 | 2,000 | |
| | .5 Emission Monitoring | 29,739 | 30,682 | 31,399 | 67,579 | 47,702 | 46,903 | 34,419 | 104,419 | 39,496 | 34,428 | 34,748 | 32,735 | 534,249 | | 534,249 |
| | .6 General Water Quality | 32,882 | 37,924 | 87,696 | 38,527 | 41,061 | 68,650 | 39,698 | 38,314 | 67,288 | 41,896 | 39,132 | 67,072 | 600,140 | 600,140 | |
| | .7 Groundwater Contamination Investigation | 106,652 | 115,264 | 56,573 | 59,514 | 66,870 | 54,790 | 54,265 | 55,578 | 59,249 | 68,182 | 116,105 | 114,176 | 927,218 | 927,218 | |
| | .8 State NPDES Administration | 23,000 | 11,500 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 34,500 | 34,500 | |
| | .9 Lead and Copper Rule | 167 | 167 | 2,667 | 167 | 167 | 2,667 | 167 | 167 | 2,667 | 167 | 167 | 2,663 | 12,000 | 12,000 | |
| | .10 Env Auditing/Assessment | 83 | 83 | 83 | 1,083 | 1,083 | 1,083 | 1,083 | 1,083 | 1,733 | 1,083 | 83 | 237 | 8,800 | 8,800 | |
| | .11 General Solid & Hazardous Waste | 16,294 | 16,056 | 17,323 | 20,235 | 16,941 | 17,672 | 16,921 | 16,923 | 20,985 | 17,844 | 18,124 | 19,455 | 214,773 | 214,773 | |
| | .12 Above Ground Storage Tanks | 0 | 0 | 26,250 | 0 | 1,200 | 26,250 | 0 | 0 | 26,250 | 0 | 0 | 26,250 | 106,200 | 106,200 | |
| | .13 Low Nox | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| | .14 Ash Pond Diversion Curtains | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| | .15 Mercury Emissions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| | .16 Sodium Injection | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| | .17 Gulf Coast Ozone Study | 600 | 1,600 | 1,600 | 1,600 | 1,600 | 1,600 | 1,600 | 1,600 | 1,600 | 1,600 | 1,600 | 3,400 | 20,000 | | 20,000 |
| | .18 SPCC Substation Project | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | .19 FDEP NOX Reduction Agreement | 0 | 0 | 0 | 28,124 | 82,755 | 90,171 | 95,450 | 96,097 | 91,463 | 92,649 | 105,233 | 75,299 | 757,241 | | 757,241 |
| | .20 Türtle Protective Lighting Program | 1,715 | 1,715 | 1,715 | 1,715 | 868 | 868 | 868 | 868 | 686 | 686 | 686 | 756 | 13,146 | 13,146 | |
| | .21 So2 Allowances | (7,704) | (7,858) | (7,913) | (7,814) | (7,656) | (7,657) | (7,617) | (7,618) | (7,745) | (7,848) | (7,877) | (7,729) | (93,036) | | (93,036) |
| 2 | Total of O & M Activities | 210,724 | 867,929 | 226,634 | 218,618 | 258,261 | 313,467 | 242,524 | 437,475 | 315,363 | 256,357 | 313,442 | 343,543 | 4,004,337 | 1,918,777 | 2,085,560 |
| 3 | Recoverable Costs Allocated to Energy | 27,931 | 685,220 | 34,327 | 97,377 | 130,071 | 141,487 | 129,522 | 324,542 | 136,505 | 126,499 | 139,145 | 112,934 | 2,085,560 | | |
| 4 | Recoverable Costs Allocated to Demand | 182,793 | 182,709 | 192,307 | 121,241 | 128,190 | 171,980 | 113,002 | 112,933 | 178,858 | 129,858 | 174,297 | 230,609 | 1,918,777 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | | | |
| 6 | Retail Demand Jurisdictional Factor | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | 26,941 | 662,942 | 33,165 | 94,261 | 126,125 | 137,285 | 125,451 | 314,209 | 131,959 | 122,297 | 134,236 | 108,959 | 2,017,830 | | |
| 8 | Jurisdictional Demand Recoverable Costs (B) | 176,667 | 176,586 | 185,862 | 117,178 | 123,894 | 166,216 | 109,215 | 109,148 | 172,864 | 125,506 | 168,456 | 222,881 | 1,854,473 | | |
| 9 | Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8) | 203,608 | 839,528 | 219,027 | 211,439 | 250,019 | 303,501 | 234,666 | 423,357 | 304,823 | 247,803 | 302,692 | 331,840 | 3,872,303 | | |

Notes:

(A) Line 3 x Line 5 x 1.0007 line loss multiplier
(B) Line 4 x Line 6

Schedule 3P

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Capital Investment Projects - Recoverable Costs**
(in Dollars)

| Line | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec | End of Period Total | Method of Classification Demand | Method of Classification Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Description of Investment Projects (A) | | | | | | | | | | | | | | | |
| | .1 Air Quality Assurance Testing | 2,881 | 2,860 | 2,838 | 2,818 | 2,797 | 2,777 | 2,756 | 2,734 | 2,714 | 2,693 | 2,673 | 2,652 | 33,193 | 0 | 33,193 |
| | .2 Crist 5, 6 & 7 Precipitator Projects | 207,214 | 206,647 | 206,080 | 205,513 | 204,946 | 204,380 | 203,812 | 203,245 | 202,678 | 202,111 | 201,544 | 200,977 | 2,449,147 | 0 | 2,449,147 |
| | .3 Crist 7 Flue Gas Conditioning | 19,579 | 19,510 | 19,440 | 19,372 | 19,301 | 19,234 | 19,164 | 19,095 | 19,025 | 18,957 | 18,887 | 18,818 | 230,382 | 0 | 230,382 |
| | .4 Low Nox Burners, Crist 6 & 7 | 192,076 | 191,672 | 191,269 | 190,866 | 190,463 | 190,058 | 189,655 | 189,252 | 188,849 | 188,444 | 184,311 | 180,219 | 2,267,134 | 0 | 2,267,134 |
| | .5 CEMs- Plant Crist, Scholz, Smith, and Daniel | 62,158 | 62,017 | 61,909 | 61,989 | 62,354 | 62,529 | 62,549 | 62,568 | 62,722 | 63,444 | 63,992 | 64,066 | 752,297 | 0 | 752,297 |
| | .6 Sub. Contam. Mobile Groundwater Treat. Sys. | 9,489 | 9,471 | 9,453 | 9,435 | 9,417 | 9,399 | 9,381 | 9,363 | 9,344 | 9,326 | 9,308 | 9,290 | 112,676 | 104,008 | 8,668 |
| | .7 Raw Water Well Flowmeters - Crist & Smith | 2,737 | 2,730 | 2,723 | 2,716 | 2,709 | 2,702 | 2,695 | 2,688 | 2,681 | 2,674 | 2,667 | 2,660 | 32,382 | 29,891 | 2,491 |
| | .8 Crist Cooling Tower Cell | 8,166 | 8,136 | 8,107 | 8,076 | 8,047 | 8,016 | 7,988 | 7,957 | 7,929 | 7,898 | 7,867 | 7,838 | 96,025 | 88,638 | 7,387 |
| | .9 Crist 1-5 Dechlorination | 2,898 | 2,889 | 2,879 | 2,869 | 2,860 | 2,851 | 2,842 | 2,832 | 2,823 | 2,814 | 2,804 | 2,795 | 34,156 | 31,529 | 2,627 |
| | .10 Crist Diesel Fuel Oil Remediation | 702 | 700 | 698 | 696 | 694 | 692 | 690 | 687 | 686 | 683 | 681 | 679 | 8,288 | 7,650 | 638 |
| | .11 Crist Bulk Tanker Unload Sec Contain Struc | 964 | 961 | 958 | 955 | 952 | 949 | 945 | 942 | 939 | 936 | 933 | 930 | 11,364 | 10,490 | 874 |
| | .12 Crist IWW Sampling System | 563 | 561 | 560 | 557 | 556 | 554 | 552 | 550 | 548 | 547 | 545 | 543 | 6,636 | 6,126 | 510 |
| | .13 Smith Sodium Injection System | 1,131 | 1,129 | 1,125 | 1,123 | 1,120 | 1,117 | 1,115 | 1,112 | 1,110 | 1,106 | 1,103 | 1,101 | 13,392 | 0 | 13,392 |
| | .14 Smith Stormwater Collection System | 26,286 | 26,213 | 26,141 | 26,069 | 25,997 | 25,924 | 25,852 | 25,780 | 25,708 | 25,636 | 25,563 | 25,492 | 310,661 | 286,764 | 23,897 |
| | .15 Smith Waste Water Treatment Facility | 3,154 | 3,148 | 3,143 | 3,137 | 3,131 | 3,125 | 3,120 | 3,114 | 3,108 | 3,102 | 3,097 | 3,091 | 37,470 | 34,587 | 2,883 |
| | .16 Daniel Ash Management Project | 153,099 | 152,774 | 152,462 | 152,150 | 151,852 | 151,553 | 151,236 | 150,920 | 151,683 | 153,531 | 155,368 | 156,612 | 1,833,240 | 1,692,219 | 141,020 |
| | .17 Smith Water Conservation | 537 | 535 | 818 | 1,546 | 1,991 | 1,986 | 1,982 | 1,977 | 1,973 | 1,969 | 1,964 | 1,960 | 19,238 | 17,759 | 1,479 |
| | .18 Underground Fuel Tank Replacement | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | .19 Crist DEP Project | 478,270 | 477,089 | 475,906 | 926,103 | 1,375,205 | 1,371,839 | 1,368,473 | 1,365,106 | 1,361,739 | 1,358,373 | 1,473,979 | 1,589,299 | 13,621,381 | 0 | 13,621,381 |
| | .20 Crist Stormwater Collection System | 3,164 | 3,156 | 3,149 | 3,141 | 3,133 | 3,126 | 3,118 | 3,110 | 3,102 | 3,095 | 3,087 | 3,079 | 37,460 | 34,579 | 2,881 |
| | .21 Crist Common FTIR | 755 | 752 | 751 | 750 | 747 | 746 | 743 | 742 | 740 | 738 | 737 | 734 | 8,935 | 0 | 8,935 |
| | .22 Precipitator Upgrades for CAM Compliance | 39,512 | 40,219 | 40,940 | 41,684 | 72,683 | 103,199 | 102,978 | 102,759 | 102,538 | 102,318 | 102,097 | 101,878 | 952,805 | 0 | 952,805 |
| | .23 SO2 Allowances | 6,261 | 6,335 | 6,410 | 6,483 | 6,556 | 6,628 | 6,701 | 6,772 | 6,845 | 6,919 | 6,993 | 7,066 | 79,969 | 0 | 79,969 |
| 2 | Total Investment Projects - Recoverable Costs | 1,221,596 | 1,219,504 | 1,217,759 | 1,668,048 | 2,147,511 | 2,173,384 | 2,168,347 | 2,163,305 | 2,159,484 | 2,157,314 | 2,270,200 | 2,381,779 | 22,948,231 | 2,344,240 | 20,603,990 |
| 3 | Recoverable Costs Allocated to Energy | 1,026,126 | 1,024,482 | 1,022,906 | 1,472,959 | 1,952,428 | 1,978,728 | 1,974,131 | 1,969,532 | 1,965,155 | 1,961,427 | 2,072,768 | 2,183,348 | 20,603,990 | | |
| 4 | Recoverable Costs Allocated to Demand | 195,469 | 195,022 | 194,853 | 195,089 | 195,083 | 194,656 | 194,216 | 193,772 | 194,329 | 195,886 | 197,433 | 198,432 | 2,344,240 | | |
| 5 | Retail Energy Jurisdictional Factor | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | | | |
| 6 | Retail Demand Jurisdictional Factor | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | | | |
| 7 | Jurisdictional Energy Recoverable Costs (A) | 989,756 | 991,174 | 988,290 | 1,425,830 | 1,893,198 | 1,919,962 | 1,912,081 | 1,906,826 | 1,899,703 | 1,896,271 | 1,999,648 | 2,106,505 | 19,929,244 | | |
| 8 | Jurisdictional Demand Recoverable Costs (B) | 188,918 | 188,486 | 188,323 | 188,551 | 188,545 | 188,133 | 187,707 | 187,278 | 187,816 | 189,321 | 190,816 | 191,782 | 2,265,676 | | |
| 9 | Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8) | 1,178,674 | 1,179,660 | 1,176,613 | 1,614,381 | 2,081,743 | 2,108,095 | 2,099,788 | 2,094,104 | 2,087,519 | 2,085,592 | 2,190,464 | 2,298,287 | 22,194,920 | | |

Notes:

(A) Each project's Total System Recoverable Expenses on Schedule 4P, Line 9
(B) Line 3 x Line 5 x 1.0007 line loss multiplier
(C) Line 4 x Line 6

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

| Line | Description | Beginning of Period Amount | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | 328,697 | |
| 3 | Less: Accumulated Depreciation ( C ) | (255,904) | (258,108) | (260,312) | (262,516) | (264,720) | (266,924) | (269,128) | (271,332) | (273,536) | (275,740) | (277,944) | (280,148) | (282,352) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 72,793 | 70,589 | 68,385 | 66,181 | 63,977 | 61,773 | 59,569 | 57,365 | 55,161 | 52,957 | 50,753 | 48,549 | 46,345 | |
| 6 | Average Net Investment | | 71,691 | 69,487 | 67,283 | 65,079 | 62,875 | 60,671 | 58,467 | 56,263 | 54,059 | 51,855 | 49,651 | 47,447 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 527 | 511 | 494 | 478 | 462 | 446 | 430 | 413 | 397 | 381 | 365 | 349 | 5,253 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 150 | 145 | 140 | 136 | 131 | 127 | 122 | 117 | 113 | 108 | 104 | 99 | 1,492 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b Amortization (F) | | 2,204 | 2,204 | 2,204 | 2,204 | 2,204 | 2,204 | 2,204 | 2,204 | 2,204 | 2,204 | 2,204 | 2,204 | 26,448 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 2,881 | 2,860 | 2,838 | 2,818 | 2,797 | 2,777 | 2,756 | 2,734 | 2,714 | 2,693 | 2,673 | 2,652 | 33,193 |
| | a Recoverable Costs Allocated to Energy | | 2,881 | 2,860 | 2,838 | 2,818 | 2,797 | 2,777 | 2,756 | 2,734 | 2,714 | 2,693 | 2,673 | 2,652 | 33,193 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 2,779 | 2,767 | 2,742 | 2,728 | 2,712 | 2,695 | 2,669 | 2,647 | 2,624 | 2,604 | 2,579 | 2,559 | 32,105 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 2,779 | 2,767 | 2,742 | 2,728 | 2,712 | 2,695 | 2,669 | 2,647 | 2,624 | 2,604 | 2,579 | 2,559 | 32,105 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) N/A
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1119, 1216, 1243
(in Dollars)

| Line | Description | Beginning of Period Amount | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 13,911,401 | 13,911,401 | 13,911,401 | 13,911,401 | 13,911,401 | 13,911,401 | 13,911,401 | 13,911,401 | 13,911,401 | 13,911,401 | 13,911,401 | 13,911,401 | 13,911,401 | |
| 3 | Less: Accumulated Depreciation ( C ) | 1,712,438 | 1,652,336 | 1,592,234 | 1,532,131 | 1,472,029 | 1,411,927 | 1,351,824 | 1,291,722 | 1,231,620 | 1,171,518 | 1,111,415 | 1,051,313 | 991,210 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 15,623,839 | 15,563,737 | 15,503,635 | 15,443,532 | 15,383,430 | 15,323,328 | 15,263,225 | 15,203,123 | 15,143,021 | 15,082,919 | 15,022,816 | 14,962,714 | 14,902,611 | |
| 6 | Average Net Investment | | 15,593,788 | 15,533,686 | 15,473,584 | 15,413,481 | 15,353,379 | 15,293,277 | 15,233,174 | 15,173,072 | 15,112,970 | 15,052,868 | 14,992,765 | 14,932,663 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 114,568 | 114,126 | 113,684 | 113,243 | 112,801 | 112,360 | 111,918 | 111,477 | 111,035 | 110,593 | 110,152 | 109,710 | 1,345,667 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 32,544 | 32,419 | 32,293 | 32,168 | 32,043 | 31,917 | 31,792 | 31,666 | 31,541 | 31,415 | 31,290 | 31,164 | 382,252 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 45,212 | 45,212 | 45,212 | 45,212 | 45,212 | 45,212 | 45,212 | 45,212 | 45,212 | 45,212 | 45,212 | 45,212 | 542,544 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 14,890 | 14,890 | 14,891 | 14,890 | 14,890 | 14,891 | 14,890 | 14,890 | 14,890 | 14,891 | 14,890 | 14,891 | 178,684 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 207,214 | 206,647 | 206,080 | 205,513 | 204,946 | 204,380 | 203,812 | 203,245 | 202,678 | 202,111 | 201,544 | 200,977 | 2,449,147 |
| | a Recoverable Costs Allocated to Energy | | 207,214 | 206,647 | 206,080 | 205,513 | 204,946 | 204,380 | 203,812 | 203,245 | 202,678 | 202,111 | 201,544 | 200,977 | 2,449,147 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 199,869 | 199,929 | 199,106 | 198,937 | 198,729 | 198,310 | 197,406 | 196,774 | 195,928 | 195,397 | 194,434 | 193,904 | 2,368,723 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 199,869 | 199,929 | 199,106 | 198,937 | 198,729 | 198,310 | 197,406 | 196,774 | 195,928 | 195,397 | 194,434 | 193,904 | 2,368,723 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

05

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**
**Return on Capital Investments, Depreciation and Taxes**
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | 2,179,245 | |
| 3 | Less: Accumulated Depreciation ( C ) | (878,156) | (885,495) | (892,835) | (900,174) | (907,514) | (914,853) | (922,193) | (929,532) | (936,872) | (944,211) | (951,551) | (958,890) | (966,230) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 1,301,089 | 1,293,750 | 1,286,410 | 1,279,071 | 1,271,731 | 1,264,392 | 1,257,052 | 1,249,713 | 1,242,373 | 1,235,034 | 1,227,694 | 1,220,355 | 1,213,015 | |
| 6 | Average Net Investment | | 1,297,420 | 1,290,080 | 1,282,741 | 1,275,401 | 1,268,062 | 1,260,722 | 1,253,383 | 1,246,043 | 1,238,704 | 1,231,364 | 1,224,025 | 1,216,685 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 9,532 | 9,478 | 9,424 | 9,370 | 9,316 | 9,263 | 9,209 | 9,155 | 9,101 | 9,047 | 8,993 | 8,939 | 110,827 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 2,708 | 2,692 | 2,677 | 2,662 | 2,646 | 2,631 | 2,616 | 2,600 | 2,585 | 2,570 | 2,555 | 2,539 | 31,481 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 7,083 | 84,996 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 256 | 257 | 256 | 257 | 256 | 257 | 256 | 257 | 256 | 257 | 256 | 257 | 3,078 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 19,579 | 19,510 | 19,440 | 19,372 | 19,301 | 19,234 | 19,164 | 19,095 | 19,025 | 18,957 | 18,887 | 18,818 | 230,382 |
| | a Recoverable Costs Allocated to Energy | | 19,579 | 19,510 | 19,440 | 19,372 | 19,301 | 19,234 | 19,164 | 19,095 | 19,025 | 18,957 | 18,887 | 18,818 | 230,382 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 18,885 | 18,876 | 18,782 | 18,752 | 18,715 | 18,663 | 18,562 | 18,487 | 18,391 | 18,327 | 18,221 | 18,156 | 222,817 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 18,885 | 18,876 | 18,782 | 18,752 | 18,715 | 18,663 | 18,562 | 18,487 | 18,391 | 18,327 | 18,221 | 18,156 | 222,817 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.00007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**
**Return on Capital Investments, Depreciation and Taxes**
For Project: Low Nox Burners, Crist 6 & 7
P.E.s 1234, 1236, & 1242
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2,700,000 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200,000 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 65,000 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 13,159,921 | 13,159,921 | 13,159,921 | 13,159,921 | 13,159,921 | 13,159,921 | 13,159,921 | 13,159,921 | 13,159,921 | 13,159,921 | 13,159,921 | 10,459,921 | 10,459,921 | |
| 3 | Less: Accumulated Depreciation ( C ) | 2,687,852 | 2,645,082 | 2,602,312 | 2,559,542 | 2,516,772 | 2,474,002 | 2,431,232 | 2,388,462 | 2,345,692 | 2,302,922 | 2,260,152 | 5,056,770 | 5,022,775 | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 15,847,773 | 15,805,003 | 15,762,233 | 15,719,463 | 15,676,693 | 15,633,923 | 15,591,153 | 15,548,383 | 15,505,613 | 15,462,843 | 15,420,073 | 15,516,691 | 15,482,696 | |
| 6 | Average Net Investment | | 15,826,388 | 15,783,618 | 15,740,848 | 15,698,078 | 15,655,308 | 15,612,538 | 15,569,768 | 15,526,998 | 15,484,228 | 15,441,458 | 15,468,382 | 15,499,694 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 116,276 | 115,962 | 115,648 | 115,334 | 115,020 | 114,705 | 114,391 | 114,077 | 113,763 | 113,448 | 113,646 | 113,876 | 1,376,146 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 33,030 | 32,940 | 32,851 | 32,762 | 32,673 | 32,583 | 32,494 | 32,405 | 32,316 | 32,226 | 32,283 | 32,348 | 390,911 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 42,770 | 42,770 | 42,770 | 42,770 | 42,770 | 42,770 | 42,770 | 42,770 | 42,770 | 42,770 | 38,382 | 33,995 | 500,077 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 192,076 | 191,672 | 191,269 | 190,866 | 190,463 | 190,058 | 189,655 | 189,252 | 188,849 | 188,444 | 184,311 | 180,219 | 2,267,134 |
| | a Recoverable Costs Allocated to Energy | | 192,076 | 191,672 | 191,269 | 190,866 | 190,463 | 190,058 | 189,655 | 189,252 | 188,849 | 188,444 | 184,311 | 180,219 | 2,267,134 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 185,268 | 185,440 | 184,796 | 184,759 | 184,685 | 184,414 | 183,694 | 183,227 | 182,559 | 182,184 | 177,809 | 173,876 | 2,192,711 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 185,268 | 185,440 | 184,796 | 184,759 | 184,685 | 184,414 | 183,694 | 183,227 | 182,559 | 182,184 | 177,809 | 173,876 | 2,192,711 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: CEMs- Plant Crist, Scholz, Smith, and Daniel
P.E.s 1154, 1164, 1217, 1240, 1245, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1325, 1330, 1440, 1441, 1442, 1454, 1459, 1460, 1558, 1570
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 40,000 | 40,000 | 0 | 27,510 | 0 | 35,233 | 100,000 | 20,000 | 20,000 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 80,000 | 0 | 0 | 0 | 84,602 | 80,000 | 0 | 0 | |
| | c Retirements | | 20,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 3,937,842 | 3,917,842 | 3,917,842 | 3,917,842 | 3,917,842 | 3,997,842 | 3,997,842 | 3,997,842 | 3,997,842 | 4,082,444 | 4,162,444 | 4,162,444 | 4,162,444 | |
| 3 | Less: Accumulated Depreciation ( C ) | 1,262,697 | 1,271,170 | 1,259,675 | 1,248,180 | 1,236,685 | 1,225,093 | 1,213,405 | 1,201,717 | 1,190,029 | 1,178,242 | 1,166,260 | 1,154,182 | 1,142,104 | |
| 4 | CWIP - Non Interest Bearing | 41,859 | 41,859 | 41,859 | 41,859 | 81,859 | 41,859 | 41,859 | 69,369 | 69,369 | 20,000 | 40,000 | 60,000 | 80,000 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 5,242,398 | 5,230,871 | 5,219,376 | 5,207,881 | 5,236,386 | 5,264,794 | 5,253,106 | 5,268,928 | 5,257,240 | 5,280,686 | 5,368,704 | 5,376,626 | 5,384,548 | |
| 6 | Average Net Investment | | 5,236,635 | 5,225,124 | 5,213,629 | 5,222,134 | 5,250,590 | 5,258,950 | 5,261,017 | 5,263,084 | 5,268,963 | 5,324,695 | 5,372,665 | 5,380,587 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 38,474 | 38,389 | 38,305 | 38,367 | 38,576 | 38,638 | 38,653 | 38,668 | 38,711 | 39,121 | 39,473 | 39,531 | 464,906 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 10,929 | 10,905 | 10,881 | 10,899 | 10,958 | 10,975 | 10,980 | 10,984 | 10,996 | 11,113 | 11,213 | 11,229 | 132,062 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 11,527 | 11,495 | 11,495 | 11,495 | 11,592 | 11,688 | 11,688 | 11,688 | 11,787 | 11,982 | 12,078 | 12,078 | 140,593 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 1,228 | 1,228 | 1,228 | 1,228 | 1,228 | 1,228 | 1,228 | 1,228 | 1,228 | 1,228 | 1,228 | 1,228 | 14,736 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 62,158 | 62,017 | 61,909 | 61,989 | 62,354 | 62,529 | 62,549 | 62,568 | 62,722 | 63,444 | 63,992 | 64,066 | 752,297 |
| | a Recoverable Costs Allocated to Energy | | 62,158 | 62,017 | 61,909 | 61,989 | 62,354 | 62,529 | 62,549 | 62,568 | 62,722 | 63,444 | 63,992 | 64,066 | 752,297 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 59,955 | 60,001 | 59,814 | 60,006 | 60,462 | 60,672 | 60,583 | 60,576 | 60,633 | 61,336 | 61,735 | 61,811 | 727,584 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 59,955 | 60,001 | 59,814 | 60,006 | 60,462 | 60,672 | 60,583 | 60,576 | 60,633 | 61,336 | 61,735 | 61,811 | 727,584 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist, $2,322,037; Scholz $486,599; Smith $685,842; Daniel $533,363. Ending Balances: Crist, $2,232,037; Scholz $646,599; Smith $685,842; Daniel $617,965
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist: 3.9%; Smith 3.3%; Scholz 2.9%; Daniel 2.8% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**
**Return on Capital Investments, Depreciation and Taxes**
For Project: Sub. Contam. Mobile Groundwater Treat. Sys.
P.E. 1007, 3400, & 3412
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | 929,394 | |
| 3 | Less: Accumulated Depreciation ( C ) | (125,270) | (127,182) | (129,094) | (131,006) | (132,918) | (134,830) | (136,742) | (138,654) | (140,566) | (142,478) | (144,390) | (146,302) | (148,214) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 804,124 | 802,212 | 800,300 | 798,388 | 796,476 | 794,564 | 792,652 | 790,740 | 788,828 | 786,916 | 785,004 | 783,092 | 781,180 | |
| 6 | Average Net Investment | | 803,168 | 801,256 | 799,344 | 797,432 | 795,520 | 793,608 | 791,696 | 789,784 | 787,872 | 785,960 | 784,048 | 782,136 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 5,901 | 5,887 | 5,873 | 5,859 | 5,845 | 5,831 | 5,817 | 5,803 | 5,788 | 5,774 | 5,760 | 5,746 | 69,884 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 1,676 | 1,672 | 1,668 | 1,664 | 1,660 | 1,656 | 1,652 | 1,648 | 1,644 | 1,640 | 1,636 | 1,632 | 19,848 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 1,912 | 22,944 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 9,489 | 9,471 | 9,453 | 9,435 | 9,417 | 9,399 | 9,381 | 9,363 | 9,344 | 9,326 | 9,308 | 9,290 | 112,676 |
| | a Recoverable Costs Allocated to Energy | | 730 | 729 | 727 | 726 | 724 | 723 | 722 | 720 | 719 | 717 | 716 | 715 | 8,668 |
| | b Recoverable Costs Allocated to Demand | | 8,759 | 8,742 | 8,726 | 8,709 | 8,693 | 8,676 | 8,659 | 8,643 | 8,625 | 8,609 | 8,592 | 8,575 | 104,008 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 704 | 705 | 702 | 703 | 702 | 702 | 699 | 697 | 695 | 693 | 691 | 690 | 8,383 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 8,465 | 8,449 | 8,434 | 8,417 | 8,402 | 8,385 | 8,369 | 8,353 | 8,336 | 8,320 | 8,304 | 8,288 | 100,522 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 9,169 | 9,154 | 9,136 | 9,120 | 9,104 | 9,087 | 9,068 | 9,050 | 9,031 | 9,013 | 8,995 | 8,978 | 108,905 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Part of PE 1007 is depreciable at 2.5% annually. PEs 3400 and 3412 are depreciable at 2.5% annually.
(F) Any property that is amortized uses a 7 year amortization period. The balance of PE 1007 is amortized.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

09

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Raw Water Well Flowmeters - Crist & Smith
P.E. 1155 & 1606
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | 242,943 | |
| 3 | Less: Accumulaed Depreciation ( C ) | (31,209) | (31,952) | (32,695) | (33,438) | (34,181) | (34,924) | (35,667) | (36,410) | (37,153) | (37,896) | (38,639) | (39,382) | (40,125) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 211,734 | 210,991 | 210,248 | 209,505 | 208,762 | 208,019 | 207,276 | 206,533 | 205,790 | 205,047 | 204,304 | 203,561 | 202,818 | |
| 6 | Average Net Investment | | 211,363 | 210,620 | 209,877 | 209,134 | 208,391 | 207,648 | 206,905 | 206,162 | 205,419 | 204,676 | 203,933 | 203,190 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 1,553 | 1,547 | 1,542 | 1,537 | 1,531 | 1,526 | 1,520 | 1,515 | 1,509 | 1,504 | 1,498 | 1,493 | 18,275 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 441 | 440 | 438 | 436 | 435 | 433 | 432 | 430 | 429 | 427 | 426 | 424 | 5,191 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 743 | 743 | 743 | 743 | 743 | 743 | 743 | 743 | 743 | 743 | 743 | 743 | 8,916 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 2,737 | 2,730 | 2,723 | 2,716 | 2,709 | 2,702 | 2,695 | 2,688 | 2,681 | 2,674 | 2,667 | 2,660 | 32,382 |
| | a Recoverable Costs Allocated to Energy | | 211 | 210 | 209 | 209 | 208 | 208 | 207 | 207 | 206 | 206 | 205 | 205 | 2,491 |
| | b Recoverable Costs Allocated to Demand | | 2,526 | 2,520 | 2,514 | 2,507 | 2,501 | 2,494 | 2,488 | 2,481 | 2,475 | 2,468 | 2,462 | 2,455 | 29,891 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 204 | 203 | 202 | 202 | 202 | 202 | 200 | 200 | 199 | 199 | 198 | 198 | 2,409 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,441 | 2,436 | 2,430 | 2,423 | 2,417 | 2,410 | 2,405 | 2,398 | 2,392 | 2,385 | 2,379 | 2,373 | 28,889 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 2,645 | 2,639 | 2,632 | 2,625 | 2,619 | 2,612 | 2,605 | 2,598 | 2,591 | 2,584 | 2,577 | 2,571 | 31,298 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project. if applicable
(B) Beginning Balances: Crist, $149,921; Smith $93,023. Ending Balances: Crist, $149,921; Smith $93,023
(C) Description of Acjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.9%; Smith 3.3% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | 906,659 | |
| 3 | Less: Accumulated Depreciation ( C ) | (373,587) | (376,739) | (379,890) | (383,042) | (386,193) | (389,345) | (392,496) | (395,648) | (398,799) | (401,951) | (405,102) | (408,253) | (411,404) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 533,072 | 529,920 | 526,769 | 523,617 | 520,466 | 517,314 | 514,163 | 511,011 | 507,860 | 504,708 | 501,557 | 498,406 | 495,255 | |
| 6 | Average Net Investment | | 531,496 | 528,345 | 525,193 | 522,042 | 518,890 | 515,739 | 512,587 | 509,436 | 506,284 | 503,133 | 499,982 | 496,831 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Compcnent Grossed Up For Taxes (D) | | 3,905 | 3,882 | 3,859 | 3,835 | 3,812 | 3,789 | 3,766 | 3,743 | 3,720 | 3,697 | 3,673 | 3,650 | 45,331 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 1,109 | 1,103 | 1,096 | 1,090 | 1,083 | 1,076 | 1,070 | 1,063 | 1,057 | 1,050 | 1,043 | 1,037 | 12,877 |
| 8 | Investment Experses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 2,947 | 35,364 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 205 | 204 | 205 | 204 | 205 | 204 | 205 | 204 | 205 | 204 | 204 | 204 | 2,453 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 8,166 | 8,136 | 8,107 | 8,076 | 8,047 | 8,016 | 7,988 | 7,957 | 7,929 | 7,898 | 7,867 | 7,838 | 96,025 |
| | a Recoverable Costs Allocated to Energy | | 628 | 626 | 624 | 621 | 619 | 617 | 614 | 612 | 610 | 608 | 605 | 603 | 7,387 |
| | b Recoverable Costs Allocated to Demand | | 7,538 | 7,510 | 7,483 | 7,455 | 7,428 | 7,399 | 7,374 | 7,345 | 7,319 | 7,290 | 7,262 | 7,235 | 88,638 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictonal Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 606 | 606 | 603 | 601 | 600 | 599 | 595 | 593 | 590 | 588 | 584 | 582 | 7,147 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 7,285 | 7,258 | 7,232 | 7,205 | 7,179 | 7,151 | 7,127 | 7,099 | 7,074 | 7,046 | 7,019 | 6,993 | 85,668 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 7,891 | 7,864 | 7,835 | 7,806 | 7,779 | 7,750 | 7,722 | 7,692 | 7,664 | 7,634 | 7,603 | 7,575 | 92,815 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity compcnent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Crist 1-5 Dechlorination
P.E. 1248
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | 305,323 | |
| 3 | Less: Accumulated Depreciation ( C ) | (102,801) | (103,793) | (104,785) | (105,777) | (106,769) | (107,761) | (108,753) | (109,745) | (110,737) | (111,729) | (112,721) | (113,713) | (114,705) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 202,522 | 201,530 | 200,538 | 199,546 | 198,554 | 197,562 | 196,570 | 195,578 | 194,586 | 193,594 | 192,602 | 191,610 | 190,618 | |
| 6 | Average Net Investment | | 202,026 | 201,034 | 200,042 | 199,050 | 198,058 | 197,066 | 196,074 | 195,082 | 194,090 | 193,098 | 192,106 | 191,114 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 1,484 | 1,477 | 1,470 | 1,462 | 1,455 | 1,448 | 1,441 | 1,433 | 1,426 | 1,419 | 1,411 | 1,404 | 17,330 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 422 | 420 | 417 | 415 | 413 | 411 | 409 | 407 | 405 | 403 | 401 | 399 | 4,922 |
| 8 | Investment Experses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 992 | 992 | 992 | 992 | 992 | 992 | 992 | 992 | 992 | 992 | 992 | 992 | 11,904 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 2,898 | 2,889 | 2,879 | 2,869 | 2,860 | 2,851 | 2,842 | 2,832 | 2,823 | 2,814 | 2,804 | 2,795 | 34,156 |
| | a Recoverable Costs Allocated to Energy | | 223 | 222 | 221 | 221 | 220 | 219 | 219 | 218 | 217 | 216 | 216 | 215 | 2,627 |
| | b Recoverable Costs Allocated to Demand | | 2,675 | 2,667 | 2,658 | 2,648 | 2,640 | 2,632 | 2,623 | 2,614 | 2,606 | 2,598 | 2,588 | 2,580 | 31,529 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 215 | 215 | 214 | 214 | 213 | 212 | 212 | 211 | 210 | 209 | 208 | 207 | 2,540 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,585 | 2,578 | 2,569 | 2,559 | 2,552 | 2,544 | 2,535 | 2,526 | 2,519 | 2,511 | 2,501 | 2,494 | 30,473 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 2,800 | 2,793 | 2,783 | 2,773 | 2,765 | 2,756 | 2,747 | 2,737 | 2,729 | 2,720 | 2,709 | 2,701 | 33,013 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 67,955 | 67,955 | 67,955 | 67,955 | 67,955 | 67,955 | 67,955 | 67,955 | 67,955 | 67,955 | 67,955 | 67,955 | 67,955 | |
| 3 | Less: Accumulated Depreciation ( C ) | (16,841) | (17,062) | (17,283) | (17,504) | (17,725) | (17,946) | (18,167) | (18,388) | (18,609) | (18,830) | (19,051) | (19,272) | (19,493) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 51,114 | 50,893 | 50,672 | 50,451 | 50,230 | 50,009 | 49,788 | 49,567 | 49,346 | 49,125 | 48,904 | 48,683 | 48,462 | |
| 6 | Average Net Investment | | 51,004 | 50,783 | 50,562 | 50,341 | 50,120 | 49,899 | 49,678 | 49,457 | 49,236 | 49,015 | 48,794 | 48,573 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 375 | 373 | 371 | 370 | 368 | 367 | 365 | 363 | 362 | 360 | 358 | 357 | 4,389 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 106 | 106 | 106 | 105 | 105 | 104 | 104 | 103 | 103 | 102 | 102 | 101 | 1,247 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 221 | 221 | 221 | 221 | 221 | 221 | 221 | 221 | 221 | 221 | 221 | 221 | 2,652 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 702 | 700 | 698 | 696 | 694 | 692 | 690 | 687 | 686 | 683 | 681 | 679 | 8,288 |
| | a Recoverable Costs Allocated to Energy | | 54 | 54 | 54 | 54 | 53 | 53 | 53 | 53 | 53 | 53 | 52 | 52 | 638 |
| | b Recoverable Costs Allocated to Demand | | 648 | 646 | 644 | 642 | 641 | 639 | 637 | 634 | 633 | 630 | 629 | 627 | 7,650 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 52 | 52 | 52 | 52 | 51 | 51 | 51 | 51 | 51 | 51 | 50 | 50 | 614 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 626 | 624 | 622 | 620 | 620 | 618 | 616 | 613 | 612 | 609 | 608 | 606 | 7,394 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 678 | 676 | 674 | 672 | 671 | 669 | 667 | 664 | 663 | 660 | 658 | 656 | 8,008 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Crist Bulk Tanker Unload Sec Contain Struc
P.E. 1271
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | 101,495 | |
| 3 | Less: Accumulated Depreciation ( C ) | (34,112) | (34,442) | (34,772) | (35,102) | (35,432) | (35,762) | (36,092) | (36,422) | (36,752) | (37,082) | (37,412) | (37,742) | (38,072) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 67,383 | 67,053 | 66,723 | 66,393 | 66,063 | 65,733 | 65,403 | 65,073 | 64,743 | 64,413 | 64,083 | 63,753 | 63,423 | |
| 6 | Average Net Investment | | 67,218 | 66,888 | 66,558 | 66,228 | 65,898 | 65,568 | 65,238 | 64,908 | 64,578 | 64,248 | 63,918 | 63,588 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Compcnent Grossed Up For Taxes (D) | | 494 | 491 | 489 | 487 | 484 | 482 | 479 | 477 | 474 | 472 | 470 | 467 | 5,766 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 140 | 140 | 139 | 138 | 138 | 137 | 136 | 135 | 135 | 134 | 133 | 133 | 1,638 |
| 8 | Investment Experses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 3,960 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 964 | 961 | 958 | 955 | 952 | 949 | 945 | 942 | 939 | 936 | 933 | 930 | 11,364 |
| | a Recoverable Costs Allocated to Energy | | 74 | 74 | 74 | 73 | 73 | 73 | 73 | 72 | 72 | 72 | 72 | 72 | 874 |
| | b Recoverable Costs Allocated to Demand | | 890 | 887 | 884 | 882 | 879 | 876 | 872 | 870 | 867 | 864 | 861 | 858 | 10,490 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 71 | 72 | 71 | 71 | 71 | 71 | 71 | 70 | 70 | 70 | 69 | 69 | 846 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 860 | 857 | 854 | 852 | 850 | 847 | 843 | 841 | 838 | 835 | 832 | 829 | 10,138 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 931 | 929 | 925 | 923 | 921 | 918 | 914 | 911 | 908 | 905 | 901 | 898 | 10,984 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project. if applicable
(B) Applicable beginring of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity compcnent has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Crist IWW Sampling System
P.E. 1275
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | 59,543 | |
| 3 | Less: Accumulated Depreciation ( C ) | (20,334) | (20,528) | (20,722) | (20,916) | (21,110) | (21,304) | (21,498) | (21,692) | (21,886) | (22,080) | (22,274) | (22,468) | (22,662) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 39,209 | 39,015 | 38,821 | 38,627 | 38,433 | 38,239 | 38,045 | 37,851 | 37,657 | 37,463 | 37,269 | 37,075 | 36,881 | |
| 6 | Average Net Investment | | 39,112 | 38,918 | 38,724 | 38,530 | 38,336 | 38,142 | 37,948 | 37,754 | 37,560 | 37,366 | 37,172 | 36,978 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 287 | 286 | 285 | 283 | 282 | 280 | 279 | 277 | 276 | 275 | 273 | 272 | 3,355 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 82 | 81 | 81 | 80 | 80 | 80 | 79 | 79 | 78 | 78 | 78 | 77 | 953 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 194 | 2,328 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 563 | 561 | 560 | 557 | 556 | 554 | 552 | 550 | 548 | 547 | 545 | 543 | 6,636 |
| | a Recoverable Costs Allocated to Energy | | 43 | 43 | 43 | 43 | 43 | 43 | 42 | 42 | 42 | 42 | 42 | 42 | 510 |
| | b Recoverable Costs Allocated to Demand | | 520 | 518 | 517 | 514 | 513 | 511 | 510 | 508 | 506 | 505 | 503 | 501 | 6,126 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictonal Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 41 | 42 | 42 | 42 | 42 | 42 | 41 | 41 | 41 | 41 | 41 | 41 | 497 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 503 | 501 | 500 | 497 | 496 | 494 | 493 | 491 | 489 | 488 | 486 | 484 | 5,922 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 544 | 543 | 542 | 539 | 538 | 536 | 534 | 532 | 530 | 529 | 527 | 525 | 6,419 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**
**Return on Capital Investments, Depreciation and Taxes**
For Project: Smith Sodium Injection System
P.E. 1413
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | 106,497 | |
| 3 | Less: Accumulated Depreciation ( C ) | (17,504) | (17,797) | (18,090) | (18,383) | (18,676) | (18,969) | (19,262) | (19,555) | (19,848) | (20,141) | (20,434) | (20,727) | (21,020) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 88,993 | 88,700 | 88,407 | 88,114 | 87,821 | 87,528 | 87,235 | 86,942 | 86,649 | 86,356 | 86,063 | 85,770 | 85,477 | |
| 6 | Average Net Investment | | 88,847 | 88,554 | 88,261 | 87,968 | 87,675 | 87,382 | 87,089 | 86,796 | 86,503 | 86,210 | 85,917 | 85,624 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 653 | 651 | 648 | 646 | 644 | 642 | 640 | 638 | 636 | 633 | 631 | 629 | 7,691 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 185 | 185 | 184 | 184 | 183 | 182 | 182 | 181 | 181 | 180 | 179 | 179 | 2,185 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 3,516 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 1,131 | 1,129 | 1,125 | 1,123 | 1,120 | 1,117 | 1,115 | 1,112 | 1,110 | 1,106 | 1,103 | 1,101 | 13,392 |
| | a Recoverable Costs Allocated to Energy | | 1,131 | 1,129 | 1,125 | 1,123 | 1,120 | 1,117 | 1,115 | 1,112 | 1,110 | 1,106 | 1,103 | 1,101 | 13,392 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 1,091 | 1,092 | 1,087 | 1,087 | 1,086 | 1,084 | 1,080 | 1,077 | 1,073 | 1,069 | 1,064 | 1,062 | 12,952 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 1,091 | 1,092 | 1,087 | 1,087 | 1,086 | 1,084 | 1,080 | 1,077 | 1,073 | 1,069 | 1,064 | 1,062 | 12,952 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Smith Stormwater Collection System
P.E. 1446
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | 2,782,600 | |
| 3 | Less: Accumulaed Depreciation ( C ) | (803,610) | (811,262) | (818,914) | (826,566) | (834,218) | (841,870) | (849,522) | (857,174) | (864,826) | (872,478) | (880,130) | (887,782) | (895,434) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 1,978,990 | 1,971,338 | 1,963,686 | 1,956,034 | 1,948,382 | 1,940,730 | 1,933,078 | 1,925,426 | 1,917,774 | 1,910,122 | 1,902,470 | 1,894,818 | 1,887,166 | |
| 6 | Average Net Investment | | 1,975,164 | 1,967,512 | 1,959,860 | 1,952,208 | 1,944,556 | 1,936,904 | 1,929,252 | 1,921,600 | 1,913,948 | 1,906,296 | 1,898,644 | 1,890,992 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 14,512 | 14,455 | 14,399 | 14,343 | 14,287 | 14,230 | 14,174 | 14,118 | 14,062 | 14,006 | 13,949 | 13,893 | 170,428 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 4,122 | 4,106 | 4,090 | 4,074 | 4,058 | 4,042 | 4,026 | 4,010 | 3,994 | 3,978 | 3,962 | 3,947 | 48,409 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation E) | | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 7,652 | 91,824 |
| | b Amortization(F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 26,286 | 26,213 | 26,141 | 26,069 | 25,997 | 25,924 | 25,852 | 25,780 | 25,708 | 25,636 | 25,563 | 25,492 | 310,661 |
| | a Recoverable Costs Allocated to Energy | | 2,022 | 2,016 | 2,011 | 2,005 | 2,000 | 1,994 | 1,989 | 1,983 | 1,978 | 1,972 | 1,966 | 1,961 | 23,897 |
| | b Recoverable Costs Allocated to Demand | | 24,264 | 24,197 | 24,130 | 24,064 | 23,997 | 23,930 | 23,863 | 23,797 | 23,730 | 23,664 | 23,597 | 23,531 | 286,764 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdicional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 1,950 | 1,950 | 1,943 | 1,941 | 1,939 | 1,935 | 1,926 | 1,920 | 1,912 | 1,906 | 1,897 | 1,892 | 23,111 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 23,451 | 23,386 | 23,321 | 23,258 | 23,193 | 23,128 | 23,063 | 22,999 | 22,935 | 22,871 | 22,806 | 22,742 | 277,153 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 25,401 | 25,336 | 25,264 | 25,199 | 25,132 | 25,063 | 24,989 | 24,919 | 24,847 | 24,777 | 24,703 | 24,634 | 300,264 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable begiming of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Any property tha is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 1

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**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Smith Waster Water Treatment Facilities
P.E. 1466, 1643
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | 0 0 0 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b Clearings to Plant | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Retirements | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Cost of Removal | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Salvage | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | Plant-in-Service/Depreciation Base (B) | 220,826 | 220,826 | 220,826 | 220,826 | 220,826 | 220,826 | 220,826 | 220,826 | 220,826 | 220,826 | 220,826 | 220,826 | 220,826 | 0 |
| 3 | Less: Accumulated Depreciation ( C ) | 49,453 | 48,846 | 48,239 | 47,632 | 47,025 | 46,418 | 45,811 | 45,204 | 44,597 | 43,990 | 43,383 | 42,776 | 42,169 | 0 |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | Net Investment (Lines 2 - 3 + 4) | 270,279 | 269,672 | 269,065 | 268,458 | 267,851 | 267,244 | 266,637 | 266,030 | 265,423 | 264,816 | 264,209 | 263,602 | 262,995 | 0 |
| 6 | Average Net Investment | | 269,976 | 269,369 | 268,762 | 268,155 | 267,548 | 266,941 | 266,334 | 265,727 | 265,120 | 264,513 | 263,906 | 263,299 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 1,984 | 1,979 | 1,975 | 1,970 | 1,966 | 1,961 | 1,957 | 1,952 | 1,948 | 1,943 | 1,939 | 1,934 | 23,508 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 563 | 562 | 561 | 560 | 558 | 557 | 556 | 555 | 553 | 552 | 551 | 550 | 6,678 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 607 | 607 | 607 | 607 | 607 | 607 | 607 | 607 | 607 | 607 | 607 | 607 | 7,284 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 3,154 | 3,148 | 3,143 | 3,137 | 3,131 | 3,125 | 3,120 | 3,114 | 3,108 | 3,102 | 3,097 | 3,091 | 37,470 |
| | a Recoverable Costs Allocated to Energy | | 243 | 242 | 242 | 241 | 241 | 240 | 240 | 240 | 239 | 239 | 238 | 238 | 2,883 |
| | b Recoverable Costs Allocated to Demand | | 2,911 | 2,906 | 2,901 | 2,896 | 2,890 | 2,885 | 2,880 | 2,874 | 2,869 | 2,863 | 2,859 | 2,853 | 34,587 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 234 | 234 | 234 | 233 | 234 | 233 | 232 | 232 | 231 | 231 | 230 | 230 | 2,788 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,813 | 2,809 | 2,804 | 2,799 | 2,793 | 2,788 | 2,783 | 2,778 | 2,773 | 2,767 | 2,763 | 2,757 | 33,427 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 3,047 | 3,043 | 3,038 | 3,032 | 3,027 | 3,021 | 3,015 | 3,010 | 3,004 | 2,998 | 2,993 | 2,987 | 36,215 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Daniel Ash Management Project
P.E. 1535 and 1555
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 5,562 | 7,723 | 8,034 | 7,722 | 11,081 | 7,492 | 7,331 | 7,723 | 236,146 | 237,497 | 233,956 | 82,229 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 120,728 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 13,363,197 | 13,363,197 | 13,363,197 | 13,363,197 | 13,363,197 | 13,363,197 | 13,363,197 | 13,363,197 | 13,363,197 | 13,363,197 | 13,363,197 | 13,363,197 | 13,483,925 | |
| 3 | Less: Accumulated Depreciation ( C ) | (4,306,295) | (4,347,295) | (4,388,295) | (4,429,295) | (4,470,295) | (4,511,295) | (4,552,295) | (4,593,295) | (4,634,295) | (4,675,295) | (4,716,295) | (4,757,295) | (4,798,435) | |
| 4 | CWIP - Non Interest Bearing | 95,538 | 101,100 | 108,823 | 116,857 | 124,579 | 135,660 | 143,152 | 150,483 | 158,206 | 394,352 | 631,849 | 865,805 | 827,306 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 9,152,440 | 9,117,002 | 9,083,725 | 9,050,759 | 9,017,481 | 8,987,562 | 8,954,054 | 8,920,385 | 8,887,108 | 9,082,254 | 9,278,751 | 9,471,707 | 9,512,796 | |
| 6 | Average Net Investment | | 9,134,721 | 9,100,364 | 9,067,242 | 9,034,120 | 9,002,522 | 8,970,808 | 8,937,220 | 8,903,747 | 8,984,681 | 9,180,503 | 9,375,229 | 9,492,252 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 67,113 | 66,860 | 66,617 | 66,374 | 66,142 | 65,909 | 65,662 | 65,416 | 66,010 | 67,449 | 68,880 | 69,740 | 802,172 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 19,064 | 18,992 | 18,923 | 18,854 | 18,788 | 18,722 | 18,652 | 18,582 | 18,751 | 19,160 | 19,566 | 19,810 | 227,864 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 31,177 | 31,177 | 31,177 | 31,177 | 31,177 | 31,177 | 31,177 | 31,177 | 31,177 | 31,177 | 31,177 | 31,317 | 374,264 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 9,823 | 117,876 |
| | d Property Taxes | | 25,922 | 25,922 | 25,922 | 25,922 | 25,922 | 25,922 | 25,922 | 25,922 | 25,922 | 25,922 | 25,922 | 25,922 | 311,064 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 153,099 | 152,774 | 152,462 | 152,150 | 151,852 | 151,553 | 151,236 | 150,920 | 151,683 | 153,531 | 155,368 | 156,612 | 1,833,240 |
| | a Recoverable Costs Allocated to Energy | | 11,777 | 11,752 | 11,728 | 11,704 | 11,681 | 11,658 | 11,634 | 11,609 | 11,668 | 11,810 | 11,952 | 12,047 | 141,020 |
| | b Recoverable Costs Allocated to Demand | | 141,321 | 141,022 | 140,734 | 140,446 | 140,171 | 139,895 | 139,602 | 139,310 | 140,015 | 141,720 | 143,417 | 144,566 | 1,692,219 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictonal Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 11,360 | 11,370 | 11,331 | 11,330 | 11,327 | 11,312 | 11,268 | 11,239 | 11,279 | 11,418 | 11,530 | 11,623 | 136,387 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 136,585 | 136,296 | 136,018 | 135,739 | 135,473 | 135,207 | 134,924 | 134,641 | 135,323 | 136,971 | 138,611 | 139,721 | 1,635,509 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 147,945 | 147,666 | 147,349 | 147,069 | 146,800 | 146,519 | 146,192 | 145,880 | 146,602 | 148,389 | 150,141 | 151,344 | 1,771,896 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 2.8% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Smith Water Conservation
P.E. 1620, 1638
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | 0<br>0<br>0 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 60,000 | 60,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 120,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 47,906 | 47,906 | 47,906 | 47,906 | 167,906 | 167,906 | 167,906 | 167,906 | 167,906 | 167,906 | 167,906 | 167,906 | 167,906 | |
| 3 | Less: Accumulated Depreciation ( C ) | (4,943) | (5,075) | (5,207) | (5,339) | (5,636) | (6,098) | (6,560) | (7,022) | (7,484) | (7,946) | (8,408) | (8,870) | (9,332) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 60,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 42,963 | 42,831 | 42,699 | 102,567 | 162,270 | 161,808 | 161,346 | 160,884 | 160,422 | 159,960 | 159,498 | 159,036 | 158,574 | |
| 6 | Average Net Investment | | 42,897 | 42,765 | 72,633 | 132,419 | 162,039 | 161,577 | 161,115 | 160,653 | 160,191 | 159,729 | 159,267 | 158,805 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 315 | 314 | 534 | 973 | 1,191 | 1,187 | 1,184 | 1,180 | 1,177 | 1,174 | 1,170 | 1,167 | 11,566 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 90 | 89 | 152 | 276 | 338 | 337 | 336 | 335 | 334 | 333 | 332 | 331 | 3,283 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 132 | 132 | 132 | 297 | 462 | 462 | 462 | 462 | 462 | 462 | 462 | 462 | 4,389 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 537 | 535 | 818 | 1,546 | 1,991 | 1,986 | 1,982 | 1,977 | 1,973 | 1,969 | 1,964 | 1,960 | 19,238 |
| | a Recoverable Costs Allocated to Energy | | 41 | 41 | 63 | 119 | 153 | 153 | 152 | 152 | 152 | 151 | 151 | 151 | 1,479 |
| | b Recoverable Costs Allocated to Demand | | 496 | 494 | 755 | 1,427 | 1,838 | 1,833 | 1,830 | 1,825 | 1,821 | 1,818 | 1,813 | 1,809 | 17,759 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictonal Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 40 | 40 | 61 | 115 | 148 | 148 | 147 | 147 | 147 | 146 | 146 | 146 | 1,431 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 479 | 477 | 730 | 1,379 | 1,776 | 1,772 | 1,769 | 1,764 | 1,760 | 1,757 | 1,752 | 1,748 | 17,163 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 519 | 517 | 791 | 1,494 | 1,924 | 1,920 | 1,916 | 1,911 | 1,907 | 1,903 | 1,898 | 1,894 | 18,594 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Underground Fuel Tank Replacement
P.E. 4397
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | 457,919 | |
| 3 | Less: Accumulated Depreciation ( C ) | (457,919) | (457,919) | (457,919) | (457,919) | (457,919) | (457,919) | (457,919) | (457,919) | (457,919) | (457,919) | (457,919) | (457,919) | (457,919) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 6 | Average Net Investment | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | a Recoverable Costs Allocated to Energy | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) N/A
(F) This project was fully amortized as of December 2004.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Crist FDEP Agreement for Ozone Attainment
P.E. 1199 and P.E. 1287
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant (J) | | 0 | 0 | 0 | 71,258,872 | 0 | 0 | 0 | 0 | 0 | 0 | 18,782,314 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 38,541,850 | 38,541,850 | 38,541,850 | 38,541,850 | 109,800,722 | 109,800,722 | 109,800,722 | 109,800,722 | 109,800,722 | 109,800,722 | 109,800,722 | 128,583,036 | 128,583,036 | |
| 3 | Less: Accumulated Depreciation ( C ) | (1,060,430) | (1,185,691) | (1,310,952) | (1,436,213) | (1,677,270) | (2,034,122) | (2,390,974) | (2,747,826) | (3,104,678) | (3,461,530) | (3,818,382) | (4,205,755) | (4,623,650) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lnes 2 - 3 + 4) | 37,481,420 | 37,356,159 | 37,230,898 | 37,105,637 | 108,123,452 | 107,766,600 | 107,409,748 | 107,052,896 | 106,696,044 | 106,339,192 | 105,982,340 | 124,377,281 | 123,959,386 | |
| 6 | Average Net Investment | | 37,418,790 | 37,293,529 | 37,168,268 | 72,614,545 | 107,945,026 | 107,588,174 | 107,231,322 | 106,874,470 | 106,517,618 | 106,160,766 | 115,179,811 | 124,168,334 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 274,916 | 273,996 | 273,075 | 533,499 | 793,072 | 790,450 | 787,829 | 785,207 | 782,585 | 779,963 | 846,226 | 912,265 | 7,833,083 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 78,093 | 77,832 | 77,570 | 151,547 | 225,281 | 224,537 | 223,792 | 223,047 | 222,302 | 221,558 | 240,380 | 259,139 | 2,225,078 |
| 8 | Investment Expenes | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 125,261 | 125,261 | 125,261 | 241,057 | 356,852 | 356,852 | 356,852 | 356,852 | 356,852 | 356,852 | 387,373 | 417,895 | 3,563,220 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 478,270 | 477,089 | 475,906 | 926,103 | 1,375,205 | 1,371,839 | 1,368,473 | 1,365,106 | 1,361,739 | 1,358,373 | 1,473,979 | 1,589,299 | 13,621,381 |
| | a Recoverable Costs Allocated to Energy | | 478,270 | 477,089 | 475,906 | 926,103 | 1,375,205 | 1,371,839 | 1,368,473 | 1,365,106 | 1,361,739 | 1,358,373 | 1,473,979 | 1,589,299 | 13,621,381 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 461,318 | 461,578 | 459,801 | 896,471 | 1,333,486 | 1,331,097 | 1,325,460 | 1,321,644 | 1,316,385 | 1,313,249 | 1,421,982 | 1,533,363 | 13,175,834 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 461,318 | 461,578 | 459,801 | 896,471 | 1,333,486 | 1,331,097 | 1,325,460 | 1,321,644 | 1,316,385 | 1,313,249 | 1,421,982 | 1,533,363 | 13,175,834 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) This project qualifes for AFUDC treatment. As portions of the project are moved to P-I-S, they are included in the ECRC.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Crist Storm Water Projects - Switchyard & Other Areas
P.E. 1272, 1296
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 250,000 | 250,000 | 250,000 | 250,000 | 250,000 | 250,000 | 250,000 | 250,000 | 250,000 | 250,000 | 250,000 | 250,000 | 250,000 | |
| 3 | Less: Accumulated Depreciation ( C ) | (406) | (1,219) | (2,032) | (2,845) | (3,658) | (4,471) | (5,284) | (6,097) | (6,910) | (7,723) | (8,536) | (9,349) | (10,162) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 249,594 | 248,781 | 247,968 | 247,155 | 246,342 | 245,529 | 244,716 | 243,903 | 243,090 | 242,277 | 241,464 | 240,651 | 239,838 | |
| 6 | Average Net Investment | | 249,188 | 248,375 | 247,562 | 246,749 | 245,936 | 245,123 | 244,310 | 243,497 | 242,684 | 241,871 | 241,058 | 240,245 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 1,831 | 1,825 | 1,819 | 1,813 | 1,807 | 1,801 | 1,795 | 1,789 | 1,783 | 1,777 | 1,771 | 1,765 | 21,576 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 520 | 518 | 517 | 515 | 513 | 512 | 510 | 508 | 506 | 505 | 503 | 501 | 6,128 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 813 | 813 | 813 | 813 | 813 | 813 | 813 | 813 | 813 | 813 | 813 | 813 | 9,756 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 3,164 | 3,156 | 3,149 | 3,141 | 3,133 | 3,126 | 3,118 | 3,110 | 3,102 | 3,095 | 3,087 | 3,079 | 37,460 |
| | a Recoverable Costs Allocated to Energy | | 243 | 243 | 242 | 242 | 241 | 240 | 240 | 239 | 239 | 238 | 237 | 237 | 2,881 |
| | b Recoverable Costs Allocated to Demand | | 2,921 | 2,913 | 2,907 | 2,899 | 2,892 | 2,886 | 2,878 | 2,871 | 2,863 | 2,857 | 2,850 | 2,842 | 34,579 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9638810 | 0.9638810 | 0.9638810 | 0.9638810 | 0.9638810 | 0.9638810 | 0.9638810 | 0.9638810 | 0.9638810 | 0.9638810 | 0.9638810 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 234 | 234 | 233 | 233 | 232 | 231 | 231 | 231 | 231 | 230 | 229 | 229 | 2,778 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 2,823 | 2,815 | 2,810 | 2,802 | 2,795 | 2,789 | 2,782 | 2,775 | 2,767 | 2,761 | 2,754 | 2,747 | 33,420 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 3,057 | 3,049 | 3,043 | 3,035 | 3,027 | 3,020 | 3,013 | 3,006 | 2,998 | 2,991 | 2,983 | 2,976 | 36,198 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Crist Common FTIR Monitor
P.E. 1297
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 60,111 | 60,111 | 60,111 | 60,111 | 60,111 | 60,111 | 60,111 | 60,111 | 60,111 | 60,111 | 60,111 | 60,111 | 60,111 | |
| 3 | Less: Accumulated Depreciation ( C ) | (683) | (878) | (1,073) | (1,268) | (1,463) | (1,658) | (1,853) | (2,048) | (2,243) | (2,438) | (2,633) | (2,828) | (3,023) | |
| 4 | CWIP - Non Interest Bearing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 59,428 | 59,233 | 59,038 | 58,843 | 58,648 | 58,453 | 58,258 | 58,063 | 57,868 | 57,673 | 57,478 | 57,283 | 57,088 | |
| 6 | Average Net Investment | | 59,331 | 59,136 | 58,941 | 58,746 | 58,551 | 58,356 | 58,161 | 57,966 | 57,771 | 57,576 | 57,381 | 57,186 | |
| 7 | Return on Average Net Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 436 | 434 | 433 | 432 | 430 | 429 | 427 | 426 | 424 | 423 | 422 | 420 | 5,136 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 124 | 123 | 123 | 123 | 122 | 122 | 121 | 121 | 121 | 120 | 120 | 119 | 1,459 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E) | | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 195 | 2,340 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 755 | 752 | 751 | 750 | 747 | 746 | 743 | 742 | 740 | 738 | 737 | 734 | 8,935 |
| | a Recoverable Costs Allocated to Energy | | 755 | 752 | 751 | 750 | 747 | 746 | 743 | 742 | 740 | 738 | 737 | 734 | 8,935 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 728 | 728 | 726 | 726 | 724 | 724 | 720 | 718 | 715 | 713 | 711 | 708 | 8,641 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 728 | 728 | 726 | 726 | 724 | 724 | 720 | 718 | 715 | 713 | 711 | 708 | 8,641 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.9% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10x 1.0007 line loss multiplier

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**

**Return on Capital Investments, Depreciation and Taxes**
For Project: Precipitator Upgrades for CAM Compliance
P.E. 1462
(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Expenditures/Additions | | 75,337 | 74,515 | 78,312 | 79,336 | 4,029,987 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Clearings to Plant | | 0 | 0 | 0 | 0 | 8,488,126 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Retirements | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d Cost of Removal | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | e Salvage | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Plant-in-Service/Depreciation Base (B) | 0 | 0 | 0 | 0 | 0 | 8,488,126 | 8,488,126 | 8,488,126 | 8,488,126 | 8,488,126 | 8,488,126 | 8,488,126 | 8,488,126 | |
| 3 | Less: Accumulated Depreciation ( C ) | 0 | 0 | 0 | 0 | 0 | (11,671) | (35,013) | (58,355) | (81,697) | (105,039) | (128,381) | (151,723) | (175,065) | |
| 4 | CWIP - Non Interest Bearing | 4,150,639 | 4,225,976 | 4,300,491 | 4,378,803 | 4,458,139 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | Net Investment (Lines 2 - 3 + 4) | 4,150,639 | 4,225,976 | 4,300,491 | 4,378,803 | 4,458,139 | 8,476,455 | 8,453,113 | 8,429,771 | 8,406,429 | 8,383,087 | 8,359,745 | 8,336,403 | 8,313,061 | |
| 6 | Average Net Investment | | 4,188,308 | 4,263,234 | 4,339,647 | 4,418,471 | 6,467,297 | 8,464,784 | 8,441,442 | 8,418,100 | 8,394,758 | 8,371,416 | 8,348,074 | 8,324,732 | |
| 7 | Return on AverageNet Investment | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (D) | | 30,771 | 31,322 | 31,883 | 32,463 | 47,515 | 62,191 | 62,019 | 61,848 | 61,676 | 61,505 | 61,333 | 61,162 | 605,688 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 8,741 | 8,897 | 9,057 | 9,221 | 13,497 | 17,666 | 17,617 | 17,569 | 17,520 | 17,471 | 17,422 | 17,374 | 172,052 |
| 8 | Investment Expenses | | | | | | | | | | | | | | |
| | a Depreciation (E | | 0 | 0 | 0 | 0 | 11,671 | 23,342 | 23,342 | 23,342 | 23,342 | 23,342 | 23,342 | 23,342 | 175,065 |
| | b Amortization (F) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c Dismantlement | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | d Property Taxes | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | e Other (G) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | Total System Recoverable Expenses (Lines 7 + 8) | | 39,512 | 40,219 | 40,940 | 41,684 | 72,683 | 103,199 | 102,978 | 102,759 | 102,538 | 102,318 | 102,097 | 101,878 | 952,805 |
| | a Recoverable Costs Allocated to Energy | | 39,512 | 40,219 | 40,940 | 41,684 | 72,683 | 103,199 | 102,978 | 102,759 | 102,538 | 102,318 | 102,097 | 101,878 | 952,805 |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (H) | | 38,112 | 38,911 | 39,555 | 40,350 | 70,478 | 100,134 | 99,741 | 99,487 | 99,123 | 98,919 | 98,495 | 98,292 | 921,597 |
| 13 | Retail Demand-Related Recoverable Costs (I) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | 38,112 | 38,911 | 39,555 | 40,350 | 70,478 | 100,134 | 99,741 | 99,487 | 99,123 | 98,919 | 98,495 | 98,292 | 921,597 |

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), units, or plant accounts(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Any property that is amortized uses a 7 year amortization period.
(G) Decription and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
**January 2005 - December 2005**
**Return on Capital Investments, Depreciation and Taxes**
For Project: SO2 Allowances

(in Dollars)

| Line | Description | Beginning of Period Amount | January | February | March | April | May | June | July | August | September | October | November | December | End of Period Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Investments (A) | | | | | | | | | | | | | | |
| | a Purchases/Transfers | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | b Sales/Transfers | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c Auction Proceeds/Other | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 2 | Working Capital Balance | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | a FERC 158.1 Allowance Inventory | 10,174 | 9,673 | 9,326 | 9,034 | 8,643 | 8,094 | 7,546 | 6,958 | 6,371 | 5,911 | 5,554 | 5,226 | 4,749 | |
| | b FERC 158.2 Allowances Withheld | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | c FERC 182.3 Other Regl. Assets - Losses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | d FERC 254 Regulatory Liabilities - Gains | 649,707 | 657,912 | 666,117 | 674,322 | 682,527 | 690,732 | 698,937 | 707,142 | 715,347 | 723,552 | 731,757 | 739,962 | 748,168 | |
| 3 | Total Working Capital Balance | 659,881 | 667,585 | 675,443 | 683,356 | 691,170 | 698,826 | 706,483 | 714,100 | 721,718 | 729,463 | 737,311 | 745,188 | 752,917 | |
| 4 | Average Net Working Capital Balance | | 663,733 | 671,514 | 679,400 | 687,263 | 694,998 | 702,655 | 710,292 | 717,909 | 725,591 | 733,387 | 741,250 | 749,053 | |
| 5 | Return on Average Net Working Capital Balance | | | | | | | | | | | | | | |
| | a Equity Component Grossed Up For Taxes (A) | | 4,876 | 4,934 | 4,992 | 5,049 | 5,106 | 5,162 | 5,219 | 5,274 | 5,331 | 5,388 | 5,446 | 5,503 | 62,280 |
| | b Debt Component (Line 6 x 2.5042% x 1/12) | | 1,385 | 1,401 | 1,418 | 1,434 | 1,450 | 1,466 | 1,482 | 1,498 | 1,514 | 1,531 | 1,547 | 1,563 | 17,689 |
| 6 | Total Return Component (D) | | 6,261 | 6,335 | 6,410 | 6,483 | 6,556 | 6,628 | 6,701 | 6,772 | 6,845 | 6,919 | 6,993 | 7,066 | 79,969 |
| 7 | Expenses: | | | | | | | | | | | | | | |
| | a Gains | | (8,205) | (8,205) | (8,205) | (8,205) | (8,205) | (8,205) | (8,205) | (8,205) | (8,205) | (8,205) | (8,205) | (8,206) | (98,461) |
| | b Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | c SO2 Allowance Expense | | 501 | 347 | 292 | 391 | 549 | 548 | 588 | 587 | 460 | 357 | 328 | 477 | 5,425 |
| 8 | Net Expenses (E) | | (7,704) | (7,858) | (7,913) | (7,814) | (7,656) | (7,657) | (7,617) | (7,618) | (7,745) | (7,848) | (7,877) | (7,729) | (93,036) |
| 9 | Total System Recoverable Expenses (Lines 6 + 8) | | (1,443) | (1,523) | (1,503) | (1,331) | (1,100) | (1,029) | (916) | (846) | (900) | (929) | (884) | (663) | (13,067) |
| | a Recoverable Costs Allocated to Energy | | (1,443) | (1,523) | (1,503) | (1,331) | (1,100) | (1,029) | (916) | (846) | (900) | (929) | (884) | (663) | (13,067) |
| | b Recoverable Costs Allocated to Demand | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | Energy Jurisdictional Factor | | 0.9638810 | 0.9668113 | 0.9654833 | 0.9673264 | 0.9689849 | 0.9696226 | 0.9678911 | 0.9674849 | 0.9660176 | 0.9661048 | 0.9640488 | 0.9641299 | |
| 11 | Demand Jurisdictional Factor | | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | 0.9664872 | |
| 12 | Retail Energy-Related Recoverable Costs (B) | | (1,392) | (1,473) | (1,452) | (1,288) | (1,067) | (998) | (887) | (819) | (870) | (898) | (853) | (640) | (12,637) |
| 13 | Retail Demand-Related Recoverable Costs (C) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total Juris. Recoverable Costs (Lines 12 + 13) | | (1,392) | (1,473) | (1,452) | (1,288) | (1,067) | (998) | (887) | (819) | (870) | (898) | (853) | (640) | (12,637) |

Notes:
(A) Line 4 x 8.8168% x 1/12. Based on ROE of 12% and weighted income tax rate of 38.575%
(B) Line 9a x Line 10x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 3P
(E) Line 8 is reported on Schedule 2P

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Air Quality Assurance Testing**
**PE 1006, 1244**

**Description:**
Audit test trailer with associated support equipment to conduct Relative Accuracy Audits (RATAs) on the Continuous Emission Monitoring Systems (CEMs) as required by the 1990 Clean Air Act Amendments.

**Accomplishments:**
The CEMs system in the RATA test trailer was replaced during the 2002 recovery period and was completed in January 2003. This replacement provides Gulf with the accuracy and reliability needed to accurately measure SO2, NOx, CO2, and opacity and to further maintain compliance with Clean Air Act Amendment requirements.

All RATAs have been performed in a timely and cost-effective manner and provided assurance of CEMs performance.

**Project-to-Date: $328,697**

**Progress Summary:** In-Service.

**Projections:N/A**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Crist 5, 6 & 7 Precipitator Projects**
**PE's 1119, 1216, 1243,**

**Description:**
These projects are necessary to improve particulate removal capabilities as a result of burning low sulfur coal. The larger precipitators with increased collection areas improve particulate collection efficiency.

**Accomplishments:**
No visible emission violations have occurred since installation and opacity has been substantially reduced. The precipitators have functioned successfully in burning low sulfur coal. The upgraded Crist Unit 7 precipitator was placed in service during 2004.

**Project-to-Date: $24,440,825**

**Progress Summary:** In-Service.

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Crist 7 Flue Gas Conditioning**
**PE 1228**

**Description:**
Injection of sulfur trioxide into the flue gas to improve particulate removal and improve the collection characteristics of fly ash.

**Accomplishments:**
System has proven effective in enhanced particulate removal in the precipitator.

**Project-to-Date: $2,179,245**

**Progress Summary:** In-Service.

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Low NOx Burners, Crist 6 & 7**
**PE's 1234, 1236, 1242**

**Description:**
These are unique burners installed to decrease the NOx emissions that are formed in the combustion process. This equipment is a requirement of the 1990 Clean Air Act Amendments.

**Accomplishments:**
System has proven effective in reducing NOx emissions. The low NOx burners on Unit 7 were replaced during 2003-2004 and the Unit 6 burners will be replaced during 2005.

**Project-to-Date: $20,928,110**

**Progress Summary:** In-Service.

**Projections:** $247,657

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: CEMs – Plant Crist, Scholz, Smith, and Daniel**
**PE's 1154, 1164, 1217, 1240, 1245, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1325, 1330, 1440, 1441, 1442, 1454, 1459, 1460, 1558, 1570**

**Description:**
This line item includes dilution extraction continuous emission monitors that measure concentrations of sulfur dioxide (SO2), carbon dioxide (CO2) and nitrogen oxides (NOx) in the flue gas. Opacity and flow monitors were also installed under this line item. All monitors were installed pursuant to the 1990 Clean Air Act Amendments.

**Accomplishments:**
The systems at both Gulf and Mississippi Power continue to successfully exceeded routine quality assurance/quality control (QA/QC) audits as required by the 1990 Clean Air Act Amendments.

**Project-to-Date: $6,460,751**

**Progress Summary:**
Crist 4,5,6 and 7 CEMS equipment replacements (gas analyzers, opacity monitors, and common CEMS equipment), Scholz 1 & 2 CEMS analyzer replacements, and Smith 1 gas analyzers and opacity monitor replacements were completed in 2001 and 2002. The Plant Crist Units 6 & 7 flow monitors will be replaced during fourth quarter 2004. The Plant Scholz flow monitor replacement was extended until 2005 to allow more time for advancements in technology before the replacement.

**Projections:**
Changes to the CEMs project during this projection period will include the replacement of the Plant Crist Units 4&5 CEMs shelter housing, the gas analyzers on Plant Daniel Units 1&2, and the Plant Scholz Units 1&2 flow monitors. The gas analyzers and flow monitors are necessary in order to provide Gulf with the accuracy and reliability needed to accurately measure SO2, NOx, CO2, Opacity, and flow and further maintain compliance with CAAA requirements. Capital expenditures for this project are expected to be approximately $325,000 in the remainder of 2004 and $280,000 in 2005. All of the existing analyzers are approaching the end of their useful life, and will be retired upon replacement.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Substation Contamination Mobile Groundwater Treatment System**
**PE's 1007, 3400, 3412**

**Description:**
Three groundwater treatment systems were purchased for the treatment of contaminated groundwater at substation sites.

**Accomplishments:**
Systems have proven effective in groundwater remediation.

**Project-to-Date: $929,394**

**Progress Summary:** The three systems are currently in-service and can be relocated to other substation sites after project completion.

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Raw Water Flow Meters; Crist and Smith**
**PE's 1155, 1606**

**Description:**
This capital project is necessary for Gulf to ensure compliance with an environmental requirement that is being made part of the Consumptive Use and Individual Water Use permits issued by the Northwest Florida Water Management District (NWFWMD). This requirement imposes a condition on any permit issued by the NWFWMD that requires the installation and monitoring of in-line totaling water flow meters on all existing and future water supply wells at Gulf facilities. Gulf incurred costs related to the installation and operation of new in-line totaling water flow meters at both Plant Crist and Plant Smith for implementation of this new activity.

**Accomplishments:**
The raw water flow meters have been installed at both Plant Crist and Plant Smith. The Plant Crist flow meters will need to be replaced within the next two years.

**Project-to-Date: $242,943**

**Progress Summary:** In-Service

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Crist Cooling Tower Cell**
**PE 1232**

**Description:**
Pollution control device which allows condenser cooling water to be continually reinjected into the condenser. The cooling tower function limits water discharge temperatures to meet the National Pollution Discharge Elimination System (NPDES) requirements.

**Accomplishments:**
The additional cooling tower cell has effectively enhanced temperature discharge compliance limits as required by the SPDES Permit.

**Project-to-Date: $906,659**

**Progress Summary:** In-Service.

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Crist 1-5 Dechlorination**
**PE 1248**

**Description:**
State and Federal Pollution Discharge Elimination System permits require significant reductions in chlorine discharge from the plant. This equipment injects sulfur trioxide (SO3) into the cooling water canal to chemically eliminate the residual chlorine present in discharge water.

**Accomplishments:**
The system has been effective in maintaining chlorine discharge limits.

**Project-to-Date: $305,323**

**Progress Summary:** In-Service.

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Crist Diesel Fuel Oil Remediation**
**PE 1270**

**Description:**
Monitoring wells were installed in the vicinity of storage tank systems to determine if groundwater contamination was present. The project proposed the installation of an impervious cap to reduce migration of contaminants to groundwater. FDEP has approved the proposed capping plan and the concrete cap is scheduled to be installed during the second half of 2004.

**Accomplishments:**

**Project-to-Date: $47,955**

**Progress Summary:** Monitor wells are in service. The cap will be installed during the second half 2004.

**Projections: $20,000**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Crist Bulk Tanker Unloading Secondary Containment**
**PE 1271**

**Description:**
This project was necessary to address deficiencies identified during the August 1992 Environmental Audit of Plant Crist and to minimize the potential risk of an uncontrolled discharge of pollutants into the waters of the United States. It is also a requirement of the Federal Spill Prevention Control and Countermeasures (SPCC) regulations.

**Accomplishments:**
Unloading secondary containment complies with regulatory requirements.

**Project-to-Date: $101,495**

**Progress Summary:** In-Service.

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Crist IWW Sampling System**
**PE 1275**

**Description:**
The 1993 revision to Plant Crist's wastewater discharge permit moved the compliance point from the end of the discharge canal to a point upstream of Thompson's Bayou. To allow for this sample point modification, a dock with access was constructed in the discharge canal. The work includes a small building for monitoring and sampling equipment.

**Accomplishments:**
The dock is complete and sampling events are collected at the required compliance point.

**Project-to-Date: $59,543**

**Progress Summary:** In-Service.

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Smith Sodium Injection System**
**PE 1413**

**Description:**
This project includes a silo storage tank system and components that inject sodium carbonate directly onto the coal feeder belt to enhance precipitator performance when low sulfur coal is used at Plant Smith. The injection of sodium carbonate as an additive to low sulfur coal reduces opacity levels to maintain compliance with Clean Air Act provisions.

**Accomplishments:**
The silo storage tank and components have been installed. The system is fully operational.

**Project-to-Date: $106,497**

**Progress Summary:** In Service.

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Smith Stormwater Collection System**
**PE 1446**

**Description:**
The National Pollution Discharge Elimination System (NPDES) stormwater program requires that industrial facilities install stormwater management systems in order to prevent the unpermitted discharge of contaminated stormwater runoff to the surface waters of the United States.

**Accomplishments:**
No unpermitted discharges have occurred since system installation.

**Project-to-Date: $2,782,600**

**Progress Summary:** In-Service.

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Smith Waste Water Treatment Facility**
**PE 1466, 1643**

**Description:**
During the 1990's a waste water treatment facility was installed at Plant Smith to replace the septic tank system that was installed in the early 1960's. The system was designed to provide secondary treatment of raw sewage and domestic waste from the plant proper. The treatment included aeration, chlorination, and dechlorination of the wastewater prior to discharging into a drain field. In 2004 a new waste water treatment facility with additional capacity will be installed to replace the facility installed in the 1990's. The treatment includes aeration and chlorination of the wastewater prior to discharging into the ash pond.

**Accomplishments:** Compliance maintained.

**Project-to-Date: $190,132**

**Progress Summary:** In-Service.

**Projections:**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Daniel Ash Management Project**
**PE 1535, 1555**

**Description:**
The original project included the installation of a dry ash tansport system, lining the bottom of the ash pond, closure and capping of the existing fly ash pond, and the expansion of the landfill area. Plant Daniel plans to construct a vertical expansion of the existing previously approved ash storage facility because the existing monofill is approaching the end of its storage capacity. In preparation for the completion and closure of the expansion area, Plant Daniel is developing and permitting a new on-site ash storage facility.

**Accomplishments:** No reportable exceedances have occurred since system installation.

**Project-to-Date: $13,242,469**

**Progress Summary:** In-Service.

**Projections:** $1,068,762

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Smith Water Conservation**
**PE 1620, 1638**

**Description:**
This project is a water conservation and consumptive use efficiency program to reduce the demand for groundwater and the potential for saltwater intrusion. This requirement is a specific condition of Gulf's individual water use permit for Plant Smith as issued by the Northwest Florida Water Management District, requesting a 25% reduction in the use of groundwater. Phase I of the project consisted of adding pumps, piping, valves and controls at Plant Smith to reclaim water from the ash pond.

Phase II, the Smith Closed Loop Cooling System will be installed during 2005. Currently, groundwater is used to cool steam cycle water samples. Plant Smith estimates that the proposed closed loop chiller for the laboratory sampling system would reduce water consumption by approximately 80,000 gallons per day. The Northwest Florida Water Management District has agreed that this is a valid project to pursue for continued implementation of the water conservation effort.

**Accomplishments:**

**Project-to-Date: $47,906**

**Progress Summary:** In-Service.

**Projections:** $120,000

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Underground Fuel Tank Replacement**
**PE 4397**

**Description:**
To provide for the replacement of all of Gulf's underground tanks with new above-ground tanks. The environmental laws regarding underground tanks are more stringent in regard to monitoring requirements. The risk of potential discharges of petroleum products which could result in groundwater contamination and subsequent remediation are significantly reduced with the installation of above ground systems.

**Accomplishments:**
All underground tanks have been replaced with above ground tank systems.

**Project-to-Date: $457,919**

**Progress Summary:** In-Service.

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Crist DEP Project**
**PE 1199, PE 1287**

**Description:**
The FDEP and Gulf Power entered into an agreement on August 28, 2002 to ensure compliance with the new ozone air quality standards. This agreement includes a requirement for Gulf to install Selective Catalytic Reduction (SCR) controls on Crist Unit 7, relocate the Crist Unit 7 precipitator, and install a NOx reduction technology on Plant Crist Unit 6, and Units 4 and 5 if necessary, to meet the NOx standard specified in the Agreement.

**Accomplishments:**

**Project-to-Date:** Expenditures during the construction phase qualified for AFUDC treatment; consequently, they were not included in the ECRC during that time frame. Portions of the project were moved into the ECRC as they were placed in service.

**Progress Summary:** The Crist Unit 7 precipitator was placed in service during 2004. The Crist Unit 7 SCR will be placed in service by May 1, 2005 followed by the Crist Unit 6 Selective Non-Catalytic Reduction (SNCR)/low NOX burners with Over-Fired Air (OFA) technologies being placed in service during November 2005.

**Project-to-Date: $38,541,850**

**Projections:** $54,007,856 Construction on the project will continue through 2005.

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Crist Storm Water Collection System**
**PE 1272**

**Description:**
The Plant Crist Stormwater project, (PE 1272), is required as a result of a more stringent July 17, 2002 revision to Title 40 Code of Federal Regulation Part 112, which is commonly referred to as the Spill Prevention Control and Countermeasures (SPCC) regulation. Prior to the 2002 revision, equipment containing mineral oil, such as electric transformers and regulators, were excluded from regulation. The recent revision is now inclusive of oil-containing electrical equipment. Oil-filled electrical equipment that has the potential to discharge to navigable waters must be provided with appropriate containment and/or diversionary structures to prevent such a discharge. The SPCC project at Plant Crist will route stormwater from the switchyard drain to the oil skimming sump where any potential spill would be captured, preventing the oil from reaching surface water.

**Accomplishments:**

**Project-to-Date: $7,169**

**Progress Summary:** Gulf expects will continue this project during the second half of 2004.

**Projections:** $242,831

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Crist Common FTIR**
**PE 1297**

**Description:**
The purchase of a Fourier Transform Infrared (FTIR) spectrometer, a device used to measure and analyze various low concentration stack gas emissions, will be required at Plant Crist under Title V regulations. The purchase of this instrument will enable Gulf Power to measure ammonia slip emissions required in the air construction permit on Crist Unit 7.

**Accomplishments:**

**Project-to-Date: $18,767**

**Progress Summary:** The FTIR has been purchased.

**Projections:** $41,344

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**

**Title: Precipitator Upgrades for Continuous Assurance Monitoring**
**PE 1462**

**Description:** Compliance Assurance Monitoring (CAM) Precipitator Upgrades, are required to comply with the new CAM regulations. 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 as part of the CAM plan included in Gulf's Title V Air Permit renewal applications in June, 2004. The precipitator upgrades are necessary to meet the more stringent surrogate opacity standards under CAM.

**Accomplishments:**

.

**Project-to-Date: $0**

**Progress Summary:**

**Projections: $8,488,126**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.1**

**Title: Sulfur**

**Description:**
The Crist Unit 7 sulfur trioxide (SO3) flue gas system allows the injection of SO3 into the flue gas stream. The addition of sulfur trioxide to the flue gas improves the collection efficiency of the precipitator when burning a low sulfur coal. Ammonia agglomerates the particles, which in turn enhances the collection efficiency of the precipitator.

**Accomplishments:**
The flue gas injection system has improved the efficiency of the Crist Unit 7 precipitator allowing the unit to burn low sulfur coal in compliance with the Clean Air Act Amendments (CAAA) of 1990. The need for sulfur injection varies based on the sulfur content of the available coal supply at Plant Crist, and is used when necessary to meet the sulfur dioxide emission requirements of the CAAA.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments.

**Projections: N/A**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.2**

**Title: Air Emission Fees**

**Description:**
These expenses are the annual fees required by the Florida Department of Environmental Protection (FDEP) under Title IV of the Clean Air Act Amendments of 1990.

**Accomplishments:**
Fees have been paid by due dates.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments.

**Projections: $779,874**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.3**

**Title: Title V**

**Description:**
These are expenses associated with the preparation of the Clean Air Act Amendments Title V permit applications and the subsequent implementation of Title V permits. Renewal of the Title V permit is on a five year cycle; i.e. 2005, 2010, etc.

**Accomplishments:**
Title V permits for Plants Crist, Smith, and Scholz were issued by FDEP in 1999. The Title V permit for the Pea Ridge Generating Facility was issued in July, 2000. Title V renewal applications were submitted for Plant Crist, Smith, and Scholz in June, 2004.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments.

**Projections: $87,232**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.4**

**Title: Asbestos Fees**

**Description:**
These are both annual and individual project fees due to the Florida Department of Environmental Protection (FDEP) for asbestos abatement projects.

**Accomplishments:**
Fees paid as required and on a timely basis.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments.

**Projections: $2,000**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.5**

**Title: Emission Monitoring**

**Description:**
This program provides quality assurance/quality control testing for CEMs, including Relative Accuracy Test Audits and Linearity Tests as required by the Clean Air Act Amendments (CAAA) of 1990. New activities within this category include testing for the Periodic Monitoring and Compliance Assurance Monitoring (CAM) requirements associated with the CAAA of 1990.

**Accomplishments:**
All systems are in compliance.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments

**Projections:** $534,249

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.6**

**Title: General Water Quality**

**Description:**
These are ongoing activities undertaken pursuant to the Company's NPDES permit, soil contamination studies, dechlorination, surface and groundwater monitoring studies, and the cooling water intake program. The projected increased activity in this line item is related to the addition of the Cooling Water Intake Program and the new arsenic groundwater standard.

**Accomplishments:**
All activities are on-going and comply with all applicable environmental laws, rules, and regulations.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments

**Projections: $600,140**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.7**

**Title: Groundwater Contamination Investigation**

**Description:**
This project includes sampling and testing to determine possible environmental impacts to groundwater from past herbicide applications at various substation sites. Once possible environmental impacts to groundwater have been identified then cleanup operations are initiated.

**Accomplishments:**
The Florida Department of Environmental Protection has issued a No Further Action (NFA) letter for 37 sites.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments

**Projections: $927,218**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.8**

**Title: State NPDES Administration**

**Description:**
This is the fee that is required by the State of Florida's National Pollution Discharge Elimination System (NPDES) program administration. These annual fees are required for the renewal of NPDES permits at Plants Crist, Smith and Scholz.

**Accomplishments:**
Compliance with fee due dates.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments.

**Projections: $34,500**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.9**

**Title: Lead & Copper Rule**

**Description:**
These are sampling and analytical costs for lead and copper in drinking water as required by the Florida Department of Environmental Protection (FDEP) regulations.

**Accomplishments:**
All sampling and analytical protocols are current.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments.

**Projections: $12,000**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.10**

**Title: Environmental Auditing/Assessment**

**Description:**
This program ensures continued compliance with environmental laws, rules, and regulations through auditing and/or assessment of company facilities and operations.

**Accomplishments:**
Audits and assessments accomplished to date have demonstrated compliance with environmental laws, rules, and regulations.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments.

**Projections: $8,800**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.11**

**Title: General Solid and Hazardous Waste**

**Description:**
This program provides for the proper identification, handling, storage, transportation and disposal of solid and hazardous wastes.

**Accomplishments:**
Gulf has complied with all hazardous and solid wastes regulations.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments.

**Projections: $214,773**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.12**

**Title: Above Ground Storage Tanks**

**Description:**
This project is required under the provisions of Chapter 62-762, F.A.C. and includes specific performance standards applicable to storage tank systems. These performance standards include installation of secondary containment, cathodic protection and tank integrity inspections. In-service API 653 inspections were required for Gulf's field erected above ground storage tanks during 2004.

**Accomplishments:**
Gulf has complied with all petroleum storage tank requirements.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments.

**Projections: $106,200**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.13**

**Title: Low NOx**

**Description:**
This activity refers to the maintenance expenses associated with the Low NOx burner tips on Crist Units 4 & 5 and Smith Unit 1.

**Accomplishments:**
Burner tips on Plant Crist Units 4 & 5 and Plant Smith Unit 1 have been installed and are in-service.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments.

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.14**

**Title: Ash Pond Diversion Curtains**

**Description:**
This project refers to the installation of additional flow diversion curtains at the Plant Crist ash pond to effectively increase water retention time in the ash pond, thereby allowing for the sedimentation/precipitation treatment process to be more effective in reducing levels of suspended particulate from the outfall at the Plant Crist ash pond.

**Accomplishments:**
The diversion curtains have been installed.

**Fiscal Expenditures:** N/A

**Progress Summary:**

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.15**

**Title: Mercury Emissions**

**Description:** This program pertains to requirements for Gulf to periodically analyze coal shipments for mercury and chlorine content. The EPA mandated that shipments of coal would be analyzed for mercury and chlorine only during 1999. No further notices of continued sampling requirements of coal shipments beyond 1999 have been issued by EPA, therefore no expenses have been planned for this activity in 2005.

**Accomplishments:**
Coal shipments were being analyzed as required. Sampling and analytical requirements are not expected in 2005.

**Fiscal Expenditures:** N/A

**Progress Summary:**

**Projections:** N/A

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.16**

**Title: Sodium Injection**

**Description:**
This project refers to the installation of a sodium injection system at Plant Smith. The activity involves sodium injection to the coal supply at Plant Smith to enhance precipitator efficiencies when burning low sulfur coal.

**Accomplishments:**
Sodium carbonate is used at Plant Smith when low sulfur coal is burned.

**Fiscal Expenditures:** N/A

**Progress Summary:** See Accomplishments.

**Projections: N/A**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.17**

**Title: Gulf Coast Ozone Study (GCOS)**

**Description:**
Escambia and Santa Rosa counties are identified as potential ozone non-attainment areas due to the new eight-hour ambient air quality standards adopted by the U.S. Environmental Protection Agency (EPA) in accordance with Title I of the Clean Air Act Amendments of 1990. This project refers to Gulf's participation in the Gulf Coast Ozone Study (GCOS) which is a joint modeling analysis between Gulf Power and the State of Florida to provide an improved basis for assessment of eight-hour ozone air quality for Northwest Florida.

**Accomplishments:**

**Fiscal Expenditures:** N/A

**Progress Summary:**
The goal of the project is to develop strategies for ozone ambient air attainment to supplement the Florida Department of Environmental Protection (FDEP) studies to EPA for Escambia and Santa Rosa counties. Gulf expects the GCOS project to be finalized during 2006.

**Projections: $20,000**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.18**

**Title: SPCC Substation Project**

**Description:**
On July 17, 2002 EPA published a revision to Title 40 Code of Regulation Part 112, commonly referred to as the Spill Prevention Control and Countermeasures (SPCC) regulation. The revision expanded applicability of the rule to include oil containing electrical transformers and regulators, which had previously been excluded from the SPCC regulations. Gulf will be required to install additional containment and/or diversionary structures or equipment at several substations to prevent a potential discharge of mineral oil to navigable waters of the United States or adjoining shorelines.

**Accomplishments:**

**Fiscal Expenditures:** N/A

**Progress Summary:** Gulf has assessed its substations to determine which are subject to the revised SPCC regulations. Additional containment has been added to the substations that were identified as having a reasonable risk of discharging oil into navigable waters of the United States or adjoining shorelines.

**Projections: N/A**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.20**

**Title: DEP NOx Reduction Agreement**

**Description:** This line item includes the O&M cost associated with the Selective Cataltic Reduction (SCR) project that was included as part of the FDEP and Gulf Power Agreement entered into on August 28, 2002. It includes the cost of anhydrous ammonia, air monitoring, and general operation and maintenance expenses.

**Accomplishments:** The SCR is projected to be placed in service by May 1, 2005

**Fiscal Expenditures:** N/A

**Progress Summary:**

**Projections: $757,241**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
January 2005-December 2005

**Description and Progress Report of**
**Environmental Compliance Activities and Projects**
**O & M Line Item 1.21**

**Title: Protective Lighting for Sea Turtles**

**Description:** The Protective Lighting for Sea Turtles is required to meet the requirements of Title 50 Code of Federal Regulations Part 117, Endangered and Threatened Wildlife and Plants, and local County ordinances regulating artificial lighting in threatened and endangered sea turtle nesting areas. This project includes the cost to install protective sea turtle lighting in these nesting areas.

**Accomplishments:**

**Fiscal Expenditures:** N/A

**Progress Summary:**

**Projections: $13,146**

**Schedule 6P**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
**Calculation of the Energy & Demand Allocation % By Rate Class**
**January 2005 - December 2005**

| Rate Class | (1) Average 12 CP Load Factor at Meter (%) | (2) Jan - Dec. 2005 Projected Sales at Meter (KWH) | (3) Projected Avg 12 CP at Meter (KW) | (4) Demand Loss Expansion Factor | (5) Energy Loss Expansion Factor | (6) Projected Sales at Generation (KWH) | (7) Projected Avg 12 CP at Generation (KW) | (8) Percentage of KWH Sales at Generation (%) | (9) Percentage of 12 CP Demand at Generation (%) |
|---|---|---|---|---|---|---|---|---|---|
| RS, RSVP | 61.971315% | 5,115,450,000 | 942,299.64 | 1.00486476 | 1.00530097 | 5,142,566,847 | 946,883.70 | 46.61346% | 53.41387% |
| GS | 64.200053% | 210,439,000 | 37,418.53 | 1.00485887 | 1.00529775 | 211,553,853 | 37,600.34 | 1.91757% | 2.12104% |
| GSD, GSDT, GSTOU | 73.167949% | 2,554,407,000 | 398,533.75 | 1.00470565 | 1.00516604 | 2,567,603,169 | 400,409.11 | 23.27337% | 22.58714% |
| LP, LPT | 84.177808% | 1,946,335,000 | 263,946.48 | 0.98422595 | 0.98911989 | 1,925,158,661 | 259,782.98 | 17.45010% | 14.65440% |
| PX, PXT, RTP, SBS | 101.650370% | 1,073,614,000 | 120,568.84 | 0.97443817 | 0.98057253 | 1,052,756,396 | 117,486.88 | 9.54244% | 6.62745% |
| OS-I/II | 160.732077% | 105,411,000 | 7,486.51 | 1.00468934 | 1.00529485 | 105,969,135 | 7,521.62 | 0.96053% | 0.42430% |
| OS-III | 100.278526% | 26,617,000 | 3,030.03 | 1.00511513 | 1.00526827 | 26,757,226 | 3,045.53 | 0.24253% | 0.17180% |
| TOTAL | | 11,032,273,000 | 1,773,283.78 | | | 11,032,365,287 | 1,772,730.16 | 100.00000% | 100.00000% |

Notes:
(1) Average 12 CP load factor based on actual 2003 load research data
(2) Projected KWH sales for the period January 2005 - December 2005
(3) Calculated: (Col 2) / (8,760 x Col 1), (8,760 hours = the # of hours in 1 year)
(4) Based on demand losses identified in Doc. 010949-EI
(5) Based on energy losses identified in Doc. 010949-EI
(6) Col 2 x Col 5
(7) Col 3 x Col 4
(8) Col 6 / total for Col 6
(9) Col 7 / total for Col 7

**Schedule 7P**

**Gulf Power Company**
Environmental Cost Recovery Clause (ECRC)
**Calculation of the Energy & Demand Allocation % By Rate Class**
**January 2005 - December 2005**

| Rate Class | (1) Percentage of KWH Sales at Generation (%) | (2) Percentage of 12 CP Demand at Generation (%) | (3) Energy-Related Costs | (4) Demand-Related Costs | (5) Total Environmental Costs | (6) Projected Sales at Meter (KWH) | (7) Environmental Cost Recovery Factors (¢/KWH) |
|---|---|---|---|---|---|---|---|
| RS, RSVP | 46.61346% | 53.41387% | 10,156,051 | 2,145,688 | 12,301,739 | 5,115,450,000 | 0.240 |
| GS | 1.91757% | 2.12104% | 417,797 | 85,204 | 503,001 | 210,439,000 | 0.239 |
| GSD, GSDT, GSTOU | 23.27337% | 22.58714% | 5,070,758 | 907,348 | 5,978,106 | 2,554,407,000 | 0.234 |
| LP, LPT | 17.45010% | 14.65440% | 3,801,995 | 588,682 | 4,390,677 | 1,946,335,000 | 0.226 |
| PX, PXT, RTP, SBS | 9.54244% | 6.62745% | 2,079,089 | 266,231 | 2,345,320 | 1,073,614,000 | 0.218 |
| OS-I, OS-II | 0.96053% | 0.42430% | 209,278 | 17,045 | 226,323 | 105,411,000 | 0.215 |
| OS-III | 0.24253% | 0.17180% | 52,842 | 6,901 | 59,743 | 26,617,000 | 0.224 |
| TOTAL | 100.00000% | 100.00000% | $21,787,810 | $4,017,099 | $25,804,909 | 11,032,273,000 | 0.234 |

Notes:
(1) From Schedule 6P, Col 8
(2) From Schedule 6P, Col 9
(3) Col 1 x Total Energy $ from Schedule 1P, line 5
(4) Col 2 x Total Demand $ from Schedule 1P, line 5
(5) Col 3 + Col 4
(6) Projected KWH sales for the period January 2005 - December 2005
(7) Col 5 / Col 6 x 100