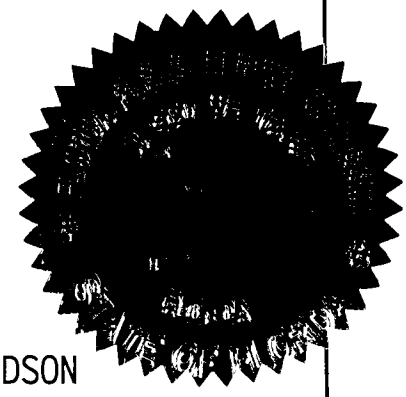
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 030007-EI

In the Matter of

ENVIRONMENTAL COST RECOVERY CLAUSE.
_____/

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN LILA A. JABER COMMISSIONER J. TERRY DEASON COMMISSIONER BRAULIO L. BAEZ COMMISSIONER RUDOLPH BRADLEY COMMISSIONER CHARLES M. DAVIDSON
DATE:	Wednesday, November 12, 2003
TIME:	Commenced at 9:30 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR OFFICIAL FPSC REPORTER (850) 413-6732

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APPEARANCES:

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CHAIRMAN JABER: 07.

MS. STERN: 07 is also fully stipulated. We do have a preliminary issue.

CHAIRMAN JABER: And what is that preliminary issue?

MS. STERN: That is that Gulf Power has deferred one of its issues, Issue 12A, which is cost-recovery for proposed scrubber study. As a result of that change, Jim Vick, we're asking that their witness, Jim Vick, be excused. And that will result in some changes to some of the exhibits, to one exhibit in particular, one of Susan Ritenour's exhibits, and it will result in stipulations of some of the generic issues.

CHAIRMAN JABER: Okay. Let's resolve the prefiled testimony first. Is it sufficient for me to just insert all of the prefiled testimony into the record with the exception of Mr. Vick's testimony?

MS. STERN: Yes.

CHAIRMAN JABER: Gulf, Mr. Badders?

MR. BADDERS: Yes. And also I believe Mr. Vick's testimony can also be inserted. There are no changes to his testimony. The only change would be to one of the exhibits to conform to the withdrawal of that one issue, or the deferral of one issue.

CHAIRMAN JABER: I see. So there is no objection to leaving his testimony into the record?

MR. BADDERS: Not that I am aware of.

CHAIRMAN JABER: Parties? Okay. Then all the prefiled testimony in Docket 030007 shall be inserted into the record at though read. And, Ms. Stern, help us out on exhibits.

MS. STERN: Okay. Exhibits KMD-1 through 3.

CHAIRMAN JABER: Shall be identified as Composite Exhibit 1.

MS. STERN: Exhibits RRL-1 through 7.

CHAIRMAN JABER: Shall be identified as Composite Exhibit 2.

MS. STERN: We are now at Susan Ritenour's exhibits, SDR-1, SDR-2, and SDR-3. We have a change to SDR-3 which we have given to the court reporter, so SDR-1 through 3, then.

CHAIRMAN JABER: And the parties -- Mr. Badders, the parties do not have any objections to the revised Exhibit SDR-3?

MR. BADDERS: That is my understanding. I have given a copy to each of the parties and to each of the Commissioners, and what we will do is show SDR-3, just call it SBR-3 revised.

CHAIRMAN JABER: Thank you. With that, SDR-1 through SBR-3, which is revised, shall be identified as Composite Exhibit 3.

MS. STERN: JP-1 through JP-3.

CHAIRMAN JABER: Will be identified as Composite

Exhibit 4.

MS. STERN: KDH-1 and KDH-2.

CHAIRMAN JABER: Will be identified as Composite Exhibit 5.

MS. STERN: PQW-1 and PQW-2.

CHAIRMAN JABER: Will be identified as Composite Exhibit 6.

MS. STERN: HTB-1 through 3.

CHAIRMAN JABER: Will be identified as Composite Exhibit 7.

MS. STERN: There are two staff stipulated exhibits which I believe none of the parties object to. The first is the final Title V permit, the second is a recommendation in Docket 030711-EI filed on October 22nd, 2003. Progress Energy's responses to staff's Interrogatories 1 through 13 in Docket Number 030711, Progress Energy's responses to staff's Interrogatories 13, 14, and 15 in Docket Number 030007. That could be a composite exhibit.

CHAIRMAN JABER: Is it correct that parties don't have any objections to the staff composite exhibit?

MR. McGEE: That's correct.

CHAIRMAN JABER: Great. Staff, your composite exhibit will be identified as Composite Exhibit 8. And Composite Exhibits 1 through 8 will be admitted into the record.

(Exhibit 1 though 8 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. 030007-EI

APRIL 1, 2003

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 April 15, 2002 through December 31, 2002.

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 April 15, 2002 through December 31, 2002. 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.

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. What is the basis for the final true-up amount which FPL is requesting for the period April 15, 2002 through December 31, 2002?

A. In Order No. PSC-01-2463-FOF-EI, the Commission approved the following stipulation concerning implementation of the provision in FPL's 1999 Stipulation and Settlement Agreement concerning recovery of Environmental Compliance Costs:

> FPL should be required to follow the provisions of the stipulation in Order No. PSC-99-0519-AS-EI, which state: "For 2002, FPL will not be allowed to recover any costs through the environmental cost recovery docket. FPL may, however, petition to recover in 2003 prudent environmental costs incurred after the expiration of the three-year term of this Stipulation and Settlement in 2002." FPL is authorized to recover these prudently incurred environmental costs in 2003. Interest, however, will not accrue on these expenses.

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

A. Form 42-1A, entitled "Calculation of the Net True-up" shows the calculation of the Net True-Up for the period April 15, 2002 through December 2002, an over-recovery of $205,349, which I am requesting to be included in the calculation of the Environmental factors for the January 2004 through December 2004 period.

The actual End-of-Period under-recovery for the period April 15, 2002 through December 2002 of $7,066,252 (shown on Form 42-1A, line 3) less the estimated/actual End-of-Period under-recovery for the same period of $7,271,601, (shown on Form 42-1A, line 6) results in the Net True-Up over-recovery for the period April 15, 2002 through December 2002 (shown on Form 42-1A, line 7) of $205,349.

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 April 15, 2002 through December 2002. The End-of-Period true-up shown on page 2 of 2, line 11 is an under-recovery of $7,066,252. Per Order No. PSC-01-2463-FOF, this actual true-up under-recovery of $7,066,252 does not include interest.

Q. Is this 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. However, as discussed earlier, per Order No. PSC-01-2463-FOF-EI, the actual true-up under-recovery of $7,066, 252 does not include interest.

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 April 15, 2002 through December 31, 2002 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 $175,802, or 5.3% lower than projected and Form 42-6A shows that total capital investment project costs were $29,100, or 0.7% lower 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 April 15, 2002 through December 31, 2002 are provided on Form 42-8A.

1. Continuous Emission Monitoring Systems (CEMS) - O & M

Project expenditures were $110,853, or 38.5% higher than anticipated. This variance is primarily due to a payment to the CEMS software support service contract with GE Energy Services, which was inadvertently excluded from the estimates for 2002.

2. Maintenance of Stationary Above Ground Fuel Storage Tanks - O&M

Project expenditures were $16,444, or 31.5% lower than anticipated. The inspection of Riviera Plant fuel oil tanks A and B was less costly than expected. Additionally, costs associated with repairs resulting from the inspection were less than expected.

3. Oil Spill Cleanup/Response Equipment - O&M

Project expenditures were $22,074, or 36.5% higher than projected. The variance was due to the execution of a large scale equipment deployment drill at the St. Lucie Waterway in Indiantown which was not originally projected to take place.

4. Resource Conservation and Recovery Act (RCRA) Corrective Action - O&M

Project expenditures were $66,506, whereas no expenditures were included for this project in the estimated/actual projections. This variance is associated with the preparation for a Visual Site Inspection at the Manatee Plant which was not originally scheduled by the Environmental Protection Agency (EPA).

5. Substation Pollutant Discharge Prevention & Removal - Distribution - O&M

Project expenditures were $241,517, or 24.3% lower than projected. Extremely heavy rains occurring from the end of May to mid-July limited FPL's ability to work on the distribution phase of the project. Deferrals of

work in the Transmission phase of the project for operational reasons prevented the shifting of unused funding to that portion of the project. The available funding resulting from the heavy rains was planned for remediation activities at the Princeton substation in the fourth quarter of 2002. Based on initial soil samplings, FPL's projection for remediating the site was $250,000. However, after further analysis during the fourth quarter of 2002, projections were reduced to $50,000 resulting in the $241,517, or 24.3% variance.

6. Substation Pollutant Discharge Prevention & Removal - Transmission - O&M

Project expenditures were $24,456, or 5.1% lower than projected. This variance was as result of three separate incidents of major substation equipment failure at the Lauderdale Plant switchyard and the Ft. Myers Plant switchyard. The Lauderdale switchyard sustained two transformer explosions and the Ft. Myers switchyard sustained one transformer explosion. As a result, FPL was unable to obtain the necessary clearances, and was therefore limited in its ability to work on the transmission phase of the project. To perform planned project work, equipment must be de-energized (clearances obtained) and temporarily taken out of service, thereby shutting down a portion of the power grid.

7. St. Lucie Turtle Net - O&M

There were no O&M expenditures for this project. The original O&M

estimate of $5,000 for diving and maintenance expenses for the last quarter of 2002, which was excluded from recovery, but inadvertently left in the estimated/actual filing.

8. Pipeline Integrity Management (PIM) – O&M

Expenses of $35,134 for payments to vendors were inadvertently recorded in a non–ECRC account. In the first quarter of 2003, an adjustment was made to correctly reflect the expense in the proper ECRC account. The remainder of the variance, $44,866 ($80,000 minus $35,134) was due to the deferral of work from late 2002 to 2003.

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

Project expenditures were $12,667, or 2.6% higher than projected. This variance is due to higher than anticipated gains from the DOE sales of emission allowances in 2002.

10. Maintenance of Stationary Above Ground Fuel Storage Tanks - Capital

Project expenditures were $28,944, or 2.6% lower than anticipated. This variance is primarily due to a $26,770 reduction in depreciation expense resulting from a retirement made in 1994 that was not removed from the depreciation calculation. The remainder of the variance is due to a $2,174 net reduction in depreciation and return between costs included in

the estimated/actual filing and actual costs for the adjustment to move a negative balance in accumulated depreciation reserve related to the Fort Myers and Sanford asset retirements recorded in March 2003 to base due to a refinement of the calculation. The adjustment amounts included in the estimated/actual filing were based on a preliminary estimate while the amounts included in this filing are based upon a more detailed analysis.

11. St. Lucie Turtle Net - Capital

Project expenditures were $5,765, or 64.4% lower than anticipated. This variance is due to the turtle nets going into service one month later than projected in the estimated/actual filing.

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. 030007-EI

August 8, 2003

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 2003 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. 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 2003 through December 2003. 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 31) 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 2003 through December 2003 is an overrecovery, including interest, of $850,933 (Appendix I, Page 4, line 5 plus line 6). This Estimated/Actual True-up overrecovery of $850,933 consists of January through June 2003 actuals and revised estimates for July through December 2003, 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 Manatee Plant in FPL's approved Wastewater/Stormwater Discharge Elimination & Reuse ("WSDER") Project which is discussed and supported in the testimony of Randall R. LaBauve.

Q. How do the Estimated/Actual project expenditures for January 2003 through December 2003 period compare with original projections?

A. Form 42-4E (Appendix I, Page 7) shows that total O&M project costs were $315,358 or 6.7% lower than projected and Form 42-6E (Appendix I, Page 10) shows that total capital investment project costs were $306,654 or 5.1% 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, pages 1 through 31 (Appendix I, Pages 13 through 43).

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

Project expenditures are estimated to be $237,723 or 10.8% lower than previously projected. Permit fees are based on tons of pollutants discharged from the fossil fuel fired power plants. These emissions are

proportionate to the amount of time and the type of fuel used at each plant. As a result of the completion of the Fort Myers Plant and Sanford Plant repowerings, less residual oil and more natural gas was burned than expected at these sites. Because natural gas produces fewer emissions than residual oil, permit fees were less than projected.

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

Project expenditures are estimated to be $127,177 or 71.0% 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.

3. Oil Spill Cleanup/Response Equipment (Project No. 8a) - O&M

Project expenditures are estimated to be $18,888 or 12.6% higher than previously projected. This variance is primarily due to an increase in the required maintenance and operation costs of spill boats and corporate spill equipment.

4. Disposal of Noncontainerized Liquid Waste (Project No. 17a) - O&M

Project expenditures are estimated to be $39,862 or 14.8% lower than previously projected. This variance is primarily due an increase in the

time needed to complete the clean out of the drying basin at the Manatee Plant. The increase in work time at the Manatee Plant has delayed the work scheduled at the Port Everglades plant to 2004.

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

Project expenditures are estimated to be $52,389 or 61.6% lower than projected. This variance is primarily due to timing differences. Work that was to be performed at the Port Everglades plant this year has been deferred to 2004.

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

Project expenditures are estimated to be $127,216 or 63.6% lower than projected. The development of the baseline assessment plan required less contractor utilization than originally expected.

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

Project expenditures are estimated to be $98,739 or 56.4% lower than projected. This variance is primarily due to a change in the implementation date for the SPCC plans from August 2003 to February 2005 by the EPA.

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

The variance of $87,914, 17.0% lower than projected, is primarily due to lower than anticipated gains from the DOE sales of emission allowances in 2003.

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

The variance is $30,835, or 2.0% lower than projected. The replacement of the CEMS Data Acquisition and Handling System (DAHS) servers and associated software upgrades is currently under review for the best technology and lowest price compliance option. An analysis is being developed based on the current system's recent failures. If the analysis shows that the replacement of the current servers and software upgrades is necessary, these expenses will be incurred 2004.

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

The variance of $126,865, 7.8% lower than projected, is due to delays in the installation of double bottoms in two tanks at the Port Everglades Plant. The delays were due to an increase in the time needed to complete the clean out of the tanks and the welding of side plates. Additionally, the installation of a tank liner at the Riviera Plant that was slated for this year has been deferred to 2004.

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

The variance of $32,072, 19.1% lower than projected, is due to Coast Guard Rule OPA-90, part of the Oil Pollution Act, which has been put on hold until further review by the Coast Guard. This rule would have required a 25% increase in oil spill equipment in 2003. The estimated cost of the new equipment is $300,000.

12. St. Lucie Turtle Net (Project No. 21) - Capital

The variance of $16,927, 24.3% higher than projected, is primarily due to additional dredging costs. More dredging was required to expose the existing anchor blocks located at the canal bottom and the additional anchoring system was more difficult to install than originally anticipated and, therefore, required more work than expected.

13. Pipeline Integrity Management (Project No. 22) - Capital

The variance of $54,952, 83.2% lower than projected, is due to delays in vendor selection which delayed the installation of positive displacement meters on the 30-inch pipeline at the Martin Plant. These installations have been deferred to 2004.

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

The variance is estimated to be $81,666 or 33.8% lower than projected,

and is primarily due to a change in the implementation date of the SPCC plans from August 2003 to February 2005 by the EPA.

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. 030007-EI

SEPTEMBER 8, 2003

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 the proposed Environmental Cost Recovery Clause (ECRC) projections for the January 2004 through December 2004 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 Environmental costs being presented for the period January 2004 through December 2004. Total environmental costs, adjusted for revenue taxes, amount to $12,945,763 (Appendix I, Page 2, Line 5a) and include $13,798,551 of environmental project costs (Appendix I, Page 2, Line 1c) decreased by the estimated/ actual overrecovery of $850,933 for the January 2003 -

December 2003 period as filed on August 8, 2003 (Appendix I, Page 2, Line 2) and the final overrecovery of $205,349 for the April 15, 2002 – December 31, 2002 period as filed on April 1, 2003 (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 O&M project 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 capital investment project costs for the projected period along with the calculation of total jurisdictional costs for these projects, classified by energy and demand.

Forms 42-2P and 42-3P present the method of classifying costs 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 70) provides the description and progress of environmental compliance activities and projects included

in the projected period.

Q. Please describe Form 42-6P.

A. Form 42-6P (Appendix I, Page 71) 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 72) 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 Pt. Everglades Electrostatic Precipitator ("ESP") Technology Project, the Underground Storage Tank Replacement/Removal ("UST Replacement/Removal") Project, and the Lowest Quality Water Source ("LQWS") Project, which are presented in the testimony of R. R. LaBauve. The projected costs for these projects

are included on the following schedules:

ESP	Project No. 25	Appendix I, Pages 5-6
UST	Project No. 26	Appendix I, Pages 3-4
LQWS	Project No. 27	Appendix I, Pages 3-4

Q. Is FPL presenting any other issues to be addressed in the ECRC?

A. Yes. Pursuant to Order No. PSC-94-0044-FOF-EI in Docket No. 930613-EI, issued on January 12, 1994, FPL is requesting recovery through the ECRC of carrying costs associated with Construction Work In Progress (CWIP) related to the Manatee Reburn Project and the Pt. Everglades ESP Technology Project capital investments. Projected capital investments associated with these projects do not qualify for an Allowance for Funds Used During Construction (AFUDC), pursuant to F.A.C. Rule 25-6.0141, and therefore, FPL is entitled to seek recovery of these carrying costs through the ECRC. FPL has included the return on CWIP for these projects for the 2004 projected period in its calculation of the 2004 ECRC factors. Additionally, the return on CWIP for these projects for 2003 will be included in the 2003 Final True-up Filing that will be filed in April of 2004.

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. 030007-EI

September 8, 2003

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present for the Commission's review and approval, three new environmental projects – the Underground Storage Tank Replacement/Removal ("UST Replacement/Removal") Project, the Lowest Quality Water Source

("LQWS") Project, and the Port Everglades Electrostatic Precipitator ("ESP") Technology 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 Administrative Code, Title 62 – Department of Environmental Protection, Rule 62-761.500.
- Document RRL-2, FPL's Existing Underground Storage Tank Systems
- Document RRL-3, St. John's River Water Management District Consumptive Use Permit Number 10652, Cape Canaveral Plant.
- Document RRL-4, St. John's River Water Management District Consumptive Use Permit Number 9202, Sanford Plant.
- Document RRL-5, Draft Title V Air Permit, Port Everglades Plant.
- Document RRL-6, Advantages/Disadvantages – Particulate Removal Technologies.
- Document RRL-7, Advantages/Disadvantages – SO_3 Removal Technologies.

UNDERGROUND STORAGE TANK ("UST") REPLACEMENT/REMOVAL PROJECT

Q. Please describe the law or regulation requiring the UST Replacement/Removal Project.

A. Florida Administrative Code (FAC) Title 62 – Department of Environmental Protection, Rule 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. This regulation requires that all single-walled underground storage tank ("UST") systems or piping in contact with the soil connected to the UST that contain pollutants or hazardous substances be removed or replaced with tanks that that are constructed with secondary containment. Storage tanks with secondary containment include double-walled USTs, double-walled aboveground storage tanks ("ASTs"), or ASTs installed with secondary containment surrounding the tank (e.g., concrete walls and floor). Rule 62-761.500 is provided as Document RRL-1.

Q. What are Category-A Storage Tank Systems?

A. Category-A Storage Tank Systems include single-walled tanks or underground single-walled piping with no secondary containment which were installed before June 30, 1992.

Q. What are Category-B Storage Tank Systems?

A. Category-B Storage Tank Systems include tanks that contain pollutants and were installed after June 30, 1992 or tanks that contain hazardous substances and were installed after January 1, 1991. Also included is any small diameter piping that comes in contact with the soil that is connected to a UST that was installed after December 10, 1990.

Q. What are Category-C Storage Tank Systems?

A. Category-C Storage Tank Systems include tanks that 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, overfill protection, and were installed on or after July of 1998.

Q. How does Rule 61-761.500 impact FPL?

A. 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. Document RRL- 2 provides a list and description of FPL's existing UST systems.

Q. Please describe the UST Replacement/Removal Project.

A. 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 ASTs 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 Rule 62-761.800 and closure assessment reports will be submitted to local counties, the Department of Environmental Resource Management (DERM) (Miami-Dade County, only), and the Florida Department of Environmental Protection (DEP).

Q. What alternatives did FPL consider?

A. FPL considered upgrading the USTs to comply with the standards for Category-C Tank Storage Systems. The cost to upgrade the USTs and integral piping would be approximately $150,000 per tank as compared to $120,000 for the removal, cost, and installation of a new AST. Additionally, environmental issues such as the hazardous nature of the contents of the USTs, their inaccessibility for inspection, and length of time in the ground were also considered in the decision to remove and replace the USTs.

Q. Why is FPL implementing the UST Replacement/Removal Project at this time?

A. FPL's decision to implement the UST Replacement/Removal Project at this time was primarily driven by environmental concerns. Due to the length of time these tanks have been underground and the potential for corrosion and leakage, FPL believes that removing/replacing them during 2004-2006 may prevent additional costs associated with containment and clean-up issues.

Q. Has FPL estimated the cost of the UST Replacement/Removal Project?

A. FPL's O&M cost estimate for the Project is $280,000, to be incurred in 2004 through 2006. FPL's timeline for the removal/replacement

of its existing USTs will ensure that the performance standards of Rule 62-761.500 are met by the date specified.

Q. Has FPL estimated how much will be spent on the Project in 2004?

A. FPL expects to spend $148,050 of O&M costs in 2004 for the removal and replacement of the USTs at Turkey Point Units 1 and 2, and the removal of the UST at the Fort Lauderdale Plant. Closure assessments for these tank systems will be performed and reports will be produced. FPL does not project that it will incur any capital costs for this project.

LOWEST QUALITY WATER SOURCE ("LQWS") PROJECT

Q. What is the statutory basis for FPL's request to recover LQWS Project costs in this docket?

A. 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 Cape Canaveral Plant CUP is provided as Document RRL-3 and the Sanford Plant CUP is provided as Document RRL-4.

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.

Q. Please briefly describe the scope of the LQWS Project at the Sanford Plant.

A. Prior to the issuance of CUP No. 9202, groundwater was used as the only source of water to the Plant's reverse osmosis water treatment system (RO system). Ground water was treated in the RO system to produce demineralized water. Demineralized water is ultra-pure water that is used in the Plant's Heat Recovery Steam Generation (HRSG)/ water/steam cycle units.

In order to comply with CUP No. 9202, both ground water and surface water must now be used as sources of water to the RO system. Surface water, which is of lower quality than groundwater, requires pretreatment prior to the RO process. The purpose of the pretreatment is to remove solids, hardness and organics from the surface water. Without pretreatment the impurities would foul the RO membranes and cause premature failure of the system.

Q. Please briefly describe the scope of the LQWS Project at the Cape Canaveral Plant.

A. As with the Sanford Plant, groundwater was used as the source of water to the Cape Canaveral RO system prior to the new CUP. However, in order to comply with CUP No. 10652, reclaimed water must now be used as a source of water to the RO system. Reclaimed water is the treated wastewater discharged from a wastewater treatment plant. It is of lower quality and greater

variability than groundwater, so like the surface water that is now used at Sanford Plant, the reclaimed water requires pretreatment prior to the RO process.

Q. What is the projected cost of the LQWS project?

A. Both the Sanford and Cape Canaveral Plants currently lease their RO system equipment from US Filter Corporation. FPL is requesting recovery of the additional O&M costs associated with the lease of pretreatment equipment from US Filter, as well as the cost of chemicals and contractor labor. For the Sanford Plant, these additional costs are projected to be $278,988 annually beginning in 2004. For the Cape Canaveral Plant, the additional O&M costs are expected to be $83,000 annually. FPL also will have to pay Brevard County $0.15 per 1,000 gallons for the reclaimed water used at the Cape Canaveral Plant, which is expected to add $8,212 annually for that plant.

Q. Does FPL expect to incur Project costs in 2003?

A. FPL estimates that it will spend $93,000 of O&M costs at the Sanford Plant beginning in September of 2003. Since my testimony reflects projections for the period January 2004 through December 2004, actual costs for 2003 will be included in the 2003 Final True-up Filing which will be filed in April of 2004.

Q. Has FPL estimated how much will be spent on the Project in 2004?

A. FPL estimates that it will spend $370,200 of O&M costs at the Sanford and Cape Canaveral Plants in 2004. As I will explain later in my testimony, FPL has not included any capital costs associated with this project in its ECRC filing.

Q. Are the costs to be incurred for the LQWS Project prudent and reasonable?

A. Yes. A lease versus purchase analysis was performed in order to determine the least cost alternative. If FPL were to purchase the pretreatment equipment, costs would be approximately $1 million. The lease for the pretreatment system has been obtained through the bidding process.

Q. What alternatives did FPL consider?

A. The SJRWMD requires the use of the lowest quality of water that is technically, environmentally and economically feasible for its needs. During the permitting process, FPL evaluated the utilization of reuse water and stormwater versus the existing use of surface (cooling pond) water for the Sanford Plant. Neither option was found to be feasible due to unavailability or lack of infrastructure to collect and manage the resource.

FPL evaluated the utilization of reuse water and stormwater versus reclaimed water at the Cape Canaveral Plant. Neither option was found to be feasible due to unavailability or lack of infrastructure to collect and manage the resource. The Port St. John's Wastewater Treatment Plant is the closest source of lowest quality, reclaimed water for the Cape Canaveral Plant. Additionally, the plant-generated wastestream boiler blowdown is already being reused at Cape Canaveral.

Q. Has FPL incurred any costs associated with the LQWS Project prior to the submittal of this petition?

A. Yes. FPL has incurred capital costs associated with two interconnect waterlines necessary for the operation of the pretreatment systems at the Sanford and Cape Canaveral Plants. The waterline at the Sanford Plant was installed in May 2003 and the waterline at the Cape Canaveral Plant is currently under construction. Additionally, beginning in May 2003, FPL has incurred O&M costs associated with the leasing of the pretreatment system at the Sanford Plant. In calculating the amount for which it is seeking recovery through the ECRC, FPL has excluded the capital costs associated with the waterlines and the 2003 O&M costs associated with the pretreatment system lease at the Sanford

Plant, since these costs were incurred prior to the submittal of this petition.

PORT EVERGLADES ELECTROSTATIC PRECIPITATOR ("ESP") TECHONOLOGY PROJECT

Q. Please briefly describe the scope of the ESP Technology Project.

A. The ESP Technology Project is the addition of pollution control measures at the four fossil fuel steam boilers at the Port Everglades plant, in order to comply with the Environmental Protection Agency's ("EPA") more stringent particulate matter emission standards required by the Port Everglades Plant Title V permit, which is scheduled to be issued by the EPA on September 7, 2003. A draft of the Port Everglades plant Title V permit is provided as Document RRL-5. FPL expects that it will be able to provide the final Port Everglades plant Title V permit on or about September 12, 2003.

Q. What is the statutory basis for FPL's request to recover ESP Technology Project costs in this docket?

A. 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), and lead (Pb). The 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 section 403.061 Florida Statutes and Chapter 62-213 F.A.C., which is administered by the 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 HAPs 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. During the renewal process for this permit, local government leaders and interested citizen groups have expressed concern that EPA's National Ambient Air Quality Standards and MACT requirements will be met at the Port Everglades plant. In this regard, the Broward County Board of County Commissioners enacted Resolution 2002-308, which called upon FPL to modify the Port Everglades plant to use cleaner technology in order to reduce the emission of pollutants. Of

special concern were particulate emissions, which result in visible plumes from the plant's exhaust stacks.

In order to avoid delay and potential disputes over the Port Everglades plant Title V permit renewal, FPL has negotiated terms for the permit that address the new standards and the public concerns. The DEP's final Title V permit for the Port Everglades plant requires FPL to install pollution control measures at all four Port Everglades units to address those concerns and to insure compliance with the EPA's emissions standards. The Port Everglades ESP Technology Project implements this requirement.

I should note that the EPA is currently developing new National Ambient Air Quality Standards to limit the emissions of fine particulates (PM2.5). The ESP Technology Project will allow the Port Everglades plant to operate to these stringent PM2.5 standards.

Q. Please describe the Port Everglades generating units.

A. The Port Everglades plant has four units with fossil fueled steam boilers, designated as Units 1, 2, 3, and 4. Units 1 and 2 have a nominal electric output rating of 200 megawatts and have identical early 1960's vintage Combustion Engineering boilers. Units 3 and

4 have a nominal electric output rating of 400 megawatts and have identical mid 1960's vintage Foster-Wheeler boilers. All four units burn primarily no. 6 residual fuel oil but also can burn natural gas. The ESP Technology Project is intended to address the particulate emissions resulting from combustion of fuel oil in the Port Everglades units.

Q. Please describe ESP technology.

A. Cold-side ESPs of the size and efficiency required to meet the specified particulate emission limits have been proven in operation on similarly sized oil-fired power plants. Historically, ESPs have been the most widely used particulate removal technology for large utility installations.

Electrostatic precipitators use transformer/rectifiers to energize discharge electrodes that produce a high voltage dc electrical field between the electrodes and grounded collecting plates. Particulate matter entering the electrical field acquires a negative charge and migrates to the grounded collecting plates. A layer of collected particles forms on the collecting plates and is removed periodically by mechanically rapping the plates. The collected particulate drops into hoppers below the precipitator and is subsequently removed by the pneumatic ash handling system.

Recent advances in ESP control technology has increased ESP collection efficiency by enhancing the plate and wire rapping cleaning cycles to match the rate at which particulate is collecting on any given plate. These computerized controls also allow the ESP to operate at the highest voltage possible without allowing sparking which reduces efficiency and increases energy usage. The ESPs that FPL will install at the Port Everglades plant in conjunction with the ESP Technology Project incorporate these advances.

Q. Would the ESPs alone meet the standards required by the new Port Everglades plant Title V permit?

A. No. There are two types of particulate emissions. The first is solid, "dry" particulates of the sort that result in dark plumes from exhaust stacks. ESPs are well suited to removing these dry particulates. The second type of particulates are in the form of condensation droplets, which produce white, steam-like plumes. ESPs cannot effectively remove condensates by themselves. The new Title V permit for the Port Everglades plant requires FPL to address both types of particulate emissions.

Fossil-fueled plants such as Port Everglades can experience condensation of sulfuric acid (which is generated from the plants' sulfur emissions) that increase measured or observed opacity. This is especially important for oil fueled units, where vanadium in the oil can serve to oxidize a greater amount of SO_2 to SO_3. As long as the exhaust gasses remain above the acid dew point temperatures, the sulfuric acid will not be read as opacity by instrumentation, nor measured as particulate emissions by EPA test procedures (which measure only filterable emissions). However, when the flue gas is cooled to condensation temperatures, plumes from these components become visible.

The ESP Technology Project will use alkaline reagent injection to address this potential for sulfuric acid to form visible condensation, including after the gases exit the exhaust stack. The alkaline reagent injection process controls the emission of SO_3 by reacting it with an alkaline material to form a particulate that can be subsequently removed by the ESPs. Two chemicals that are commonly used for this purpose are magnesium oxide/hydroxide (MgO and Mg $(OH)_2$) and sodium sulfite/bisulfite (Na_2SO_3 and $NaHSO_3$).

MgO is injected as a solution into the back passes of the boiler. The MgO and SO_3 react to form a particulate, magnesium sulfate. Some unreacted reagent remains and is removed in the downstream ESPs.

Q. What alternatives to ESPs and alkaline reagent injection did FPL consider to address the concerns over particulate emissions from the Port Everglades plant?

A. FPL first considered two alternatives to using any form of post-combustion particulate removal technology:

Repowering. FPL evaluated repowering the existing fossil steam units with natural gas-fired combined cycle plants. The use of natural gas would substantially reduce particulate emissions, but the cost of repowering made this alternative unattractive.

Exclusive Use of Natural Gas in Existing Units. FPL also looked at the economics of leaving the existing fossil steam units in place but firing them exclusively with natural gas. However, the cost of pipeline expansion and other support facilities to provide the necessary natural gas volume as well as the loss of fuel diversity that would result from agreeing not to use fuel oil made this alternative unattractive.

Once it became clear that some form of post-combustion particulate removal was needed, FPL evaluated several alternative technologies to perform this function. Document RRL-6 addresses the alternatives to ESPs that were considered, while Document RRL-7 addresses the alternatives to alkaline reagent injection. As shown on those documents, ESPs and alkaline reagent injection offer the best combination of cost, removal effectiveness and reliability.

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

A. The contracting strategy currently planned for the project to ensure prudent and reasonable costs will be as follows:

An owner's engineering contract will be negotiated on a target price basis with a penalty for exceeding the target.

a. A foundation contract will be negotiated on a target price basis (foundations on this site are considered to present the most exposure to risk of all activities performed).

b. Equipment (ESP, MgO Injection and Ash Handling) will be purchased on firm fixed lump sum contracts.

c. Construction (including ESP, Plant interface tie points, commissioning and start-up) will be performed utilizing an EPC contract (Engineering-Procurement-Construction) firm fixed

lump sum contract with schedule and performance liquidated damages.

Q. Has FPL estimated the cost of the ESP Technology Project?

A. The following is FPL's capital cost estimates for the years 2003-2007.

Year	Estimated Capital Cost
2003	$968,141
2004	$28,842,941
2005	$29,461,466
2006	$23,402,092
2007	$9,425,360
Total:	$92,100,000

Estimated annual O&M costs are $4.2 million, based on a capacity factor of 50% to 70%.

Q. Does FPL expect to incur Project costs in 2003?

A. FPL estimates that it will spend $968,141 of Capital costs beginning in the fourth quarter of 2003. These Capital costs are primarily associated with engineering design work. Since my testimony reflects projections for the period January 2004 through December

2004, these costs will be included in the 2003 Final True-up Filing which will be filed in April of 2004.

Q. Has FPL estimated how much will be spent on the Project in 2004?

A. FPL estimates that it will spend $28,842,941 of Capital costs in 2004, primarily associated with the purchase of equipment and the beginning phases of construction on Port Everglades Unit #2.

Q. What are the proposed in-service dates for implementing the ESP Technology Project at the four Port Everglades units?

A. The planned in-service dates are as follows:

Port Everglades Unit #2: Spring of 2005

Port Everglades Unit #1: Fall of 2005

Port Everglades Unit #4: Fall of 2006

Port Everglades Unit #3: Spring of 2007

Q. Is FPL recovering through any other mechanism the costs for the UST Replacement/Removal Project, the LQWS Project or the ESP Technology 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. 030007-EI
April 1, 2003

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 Manager 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 1996, I assumed my present position as Manager of Environmental Affairs.

Q. What are your responsibilities with Gulf Power Company?

A. As Manager 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, 2002 through December 31, 2002.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2002 through December 2002 with the approved estimated true-up amounts.

A. As reflected in Ms. Ritenour's Schedule 6A, the recoverable capital costs included in the estimated true-up total $8,540,399, as compared to the actual recoverable capital costs of $8,541,860. This results in a small variance of $1,461.

Q. How do the actual O&M expenses for the period January 2002 to December 2002 compare to the estimated true-up?

A. Mrs. Ritenour's Schedule 4A reflects that Gulf's recoverable environmental

O&M expenses for the current period were $2,630,858, as compared to the estimated true-up of $2,609,850. This results in a year-end variance of $21,008. I will address eight O&M projects and programs that contribute to this variance.

Q. Please explain the variance of ($19,181) 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 has not used the sulfur injection system as much as was anticipated during 2002.

Q. Please explain the variance of ($14,328) in Title V (Line Item 1.3).

A. This variance is due to less than projected legal expenses and support of the Title V negotiations previously expected to incorporate Environmental Protection Agency's eight hour ozone and fine particulate standards. Implementation of these standards has been delayed due to court challenges.

Q. Please explain the variance of ($66,989) in Emission Monitoring (Line Item 1.5).

A. Gulf's estimated true-up for Emission Monitoring includes testing and development of the compliance assurance monitoring (CAM) protocols as required by the Clean Air Act. The actual costs for CAM were less than previously anticipated due to reduced testing and associated protocol

development charges.

Q. Please explain the variance of ($11,269) 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 expenditures.

Q. Please explain the variance of $5,295 in the category entitled Environmental Auditing and Assessment (Line Item 1.10).

A. The costs associated with this program were greater than what was projected because a more extensive audit was performed at the plants during the recovery period. An unscheduled audit of district operations also contributed to the deviation.

Q. Please explain the variance of $62,237 in the category entitled General Solid & Hazardous Waste (Line Item 1.11).

A. This variance is due to unanticipated waste removal costs incurred during the projection period. More waste was generated at Gulf's facilities than originally expected.

Q. Please explain the variance of $14,411 in the category entitled Above Ground Storage Tanks (Line Item 1.12).

A. The secondary containment around the caustic and mineral acid storage tank systems at Plant Smith are to be coated with an impervious material in 2003.

The coating materials were purchased during 2002 in preparation for the scheduled work.

Q. Please explain the variance of ($9,100) 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 less than what was anticipated for the 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. 030007-EI
August 8, 2003

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 Manager 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 1996, I assumed my present position as Manager

of Environmental Affairs.

Q. What are your responsibilities with Gulf Power Company?

A. As Manager 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, 2003 through December 31, 2003. 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, 2003 through December 31, 2003 with approved projected amounts.

A. As reflected in Ms. Ritenour's Schedule 6E, the recoverable capital costs approved in the original projection total $8,505,631, as compared to the

estimated true-up amount of $8,416,756. This results in a projected variance of ($88,875). The major variance is related to CEMS, which I will discuss below.

Q. Please explain the variance of ($59,882) in the capital category entitled CEMS (Line Item 1.5).

A. This variance resulted from postponing the CEMS flow monitor replacement projects at Plant Scholz until 2005 and canceling the CEMS gas analyzer project for Units 1, 2, and 3 at Plant Crist. The Crist project was canceled because Crist Unit 1 has been retired and Units 2 and 3 will be retired by May 2006 as a result of the agreement between Gulf and the Florida Department of Environmental Protection (DEP) approved in Order No. PSC-02-1396-PAA-EI. The Scholz project was postponed after a performance evaluation was conducted which revealed that the Scholz CEMS replacement could be delayed until 2005. However, the evaluation revealed that a change in the Scholz precipitator controls is needed to restore a reasonable correlation between opacity and particulate matter. This correlation is necessary in order to be able to use opacity monitoring as a reasonable method of measuring particulate matter emissions as required by the new performance specifications of the Compliance Assurance Monitoring (CAM) requirements under Title V of the Clean Air Act. This method of monitoring is less capital intensive than a stand alone continuous particulate compliance monitor. The cost of changing the controls serves as a partial offset in this reporting cycle to the variance related to the postponment of the Scholz CEMS replacement.

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

A. Ms. Ritenour's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are now estimated to be $2,900,377 as compared to the original projection of $2,738,603. This will result in a year-end variance of $161,774. There are five O&M projects and programs contributing to this variance which I will discuss – Groundwater Contamination Investigation; Auditing/Assessment; Sodium Injection; Gulf Coast Ozone Study (GCOS); and SO_2 Allowances.

Q. Please explain the $500,508 variance in Groundwater Contamination Investigation (Line Item 1.7).

A. Due to a change in personnel during the 2003 ECRC projection cycle the expenses budgeted for geological consulting services which are recoverable costs were inadvertently excluded from the ECRC projection.

Q. Please explain the variance of $10,050 in Auditing/Assessment (Line Item 1.10).

A. As discussed in Gulf's 2002 Final True-Up, it has become necessary to conduct a more extensive auditing/assessment program in order to ensure compliance with environmental regulations. This level of activity is expected to continue.

Q. Please explain the variance of ($43,000) 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 current coal supply at Plant Smith does not require sodium injection.

Q. Please explain the variance of ($152,441) in Line Item 1.17, Gulf Coast Ozone Study (GCOS).

A. The expected completion date for the GCOS project has been extended due to a delay in the final 8 hour ozone standard rule development by the Environmental Protection Agency (EPA). Gulf expects this project to fully resume once EPA finalizes the rule.

Q. What has contributed to the ($153,343) 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. 030007-EI

September 8, 2003

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 Manager 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 1996, I assumed my present position as Manager of Environmental Affairs.

Q. What are your responsibilities with Gulf Power Company?

A. As Manager 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 2004 through December 2004.

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, have been provided to Ms. Ritenour 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. Ritenour, who has compiled the schedules and calculated the associated revenue requirements for Gulf's requested recovery.

Q. Have all of the capital projects been previously approved by the Commission?

A. No, there are three projects included in Gulf's 2004 capital projection that have not been previously approved by the Commission. These projects are related to Gulf's existing Air and Water Quality programs. In addition, this is the first time Gulf has included costs associated with the Plant Crist FDEP-Gulf Ozone Agreement previously approved by this Commission in Docket 020943-EI.

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

A. The first project (PE 1030) involves a Scrubber Study Gulf is required to conduct pursuant to the Environmental Protection Agency's (EPA) implementation of Section 112 of the Clean Air Act, which requires EPA to develop Maximum Achievable Control Technology (MACT) standards for hazardous air pollutions. The pollutant of most concern to the electric utility industry is mercury. EPA is required to propose a mercury MACT standard for coal fired electric utility boilers by December 2003. The standard is to be final by December 2004 with implementation within 3 years (2007). In order for Gulf Power to comply with the proposed MACT standard, it is imperative that Gulf determine the most cost effective

emission control strategy that will ensure compliance with the more stringent standard. Research in control technologies has demonstrated that flue gas scrubber systems have the potential to remove a significant percentage of mercury emissions from coal fired boilers. The study will determine if this technology is best suited for Plant Crist Unit 7.

The second project (PE 1297) is the purchase of a Fourier Transform Infrared (FTIR) spectrometer, a device used to measure and analyze various low concentration stack gas emissions. The purchase of this instrument will enable Gulf to measure formaldehyde in stack emissions on units affected by EPA's new MACT standards for hazardous air pollutants under Section 112 of the Clean Air Act. Additionally, the monitor will be used to measure ammonia slip emissions required in the air construction permit on Crist Unit 7.

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

A. 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 skimmer pond where any potential spill would be captured, preventing the oil from reaching surface water. Gulf expects to spend $250,000 on this project in 2004.

Q. Mr. Vick, are there any previously approved capital projects included in the 2004 capital projection that are required for environmental compliance but have yet to incur expenses?

A. Yes, 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 calls for Gulf to install Selective Catalytic Reduction (SCR) controls on Plant Crist Unit 7 and relocate the Crist Unit 7 precipitator. On August 30, 2002 Gulf petitioned to recover the costs of implementing the agreement through the ECRC. 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 consummating order PSC-02-1593-CO-EI was issued November 18, 2002. Gulf expects the first phase of this project to go in service in June 2004, at which time almost $38 million of capital investment will move into the ECRC.

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

A. There are three other previously approved capital projects that will be expanded. These include the Plant Crist Diesel Fuel Oil Remediation project, Plant Crist and Plant Daniel Continuous Emission Monitoring (CEMs) replacements, and the Plant Crist Low NOx Burner replacement.

On February 27, 2003, Gulf Power received approval from the FDEP to construct an impervious surface (concrete cap) for the Crist Diesel Fuel Oil Remediation project (PE 1270). A small area of impacted soils remain in-place at Crist and Gulf will install a concrete cap in 2004 to reduce the migration of contaminants to groundwater. Expenditures for this project are expected to be $20,000.

During the 2004 recovery period the CEMs project includes the replacement of flow monitors and the CEMs shelter for Units 6 and 7 at Plant Crist (PE 1217) and the replacement of gas analyzers at Plant Daniel on Units 1 and 2 (PE 1560). The gas analyzers and flow monitors are necessary in order to provide Gulf with the accuracy and reliability needed to measure SO2, NOx, CO2, opacity, and gas flow and further maintain compliance with the Clean Air Act Amendment (CAAA) requirements. Expenditures for this project are expected to be $242,000 and will be allocated on an energy basis, as is all other equipment associated with emission monitoring. All of the existing analyzers are

approaching the end of their useful life, and will be retired upon replacement.

Gulf previously reported that expenditures of $1.3 million are expected in late 2003 for the Unit 7 Low NOx Burners at Plant Crist. Additional expenditures of approximately $3.4 million in 2004 will be necessary to complete the project. The existing burners are approaching the end of their useful life and must be replaced in order to maintain compliance with the Clean Air Act Acid Rain Program requirements.

Q. Please compare the Environmental Operation and Maintenance (O & M) activities listed on Schedule 2P of Exhibit SDR-3 to the O & M activities approved for cost recovery in past ECRC dockets.

A. All of the O & M activities listed on Schedule 2P have been approved for recovery through the ECRC in past proceedings except for Line Item 1.18, SPCC Substation Project. The O & M activities are grouped into four major categories: Air Quality, Water Quality, Environmental Affairs Administration, and Solid and Hazardous Waste.

Q. Mr. Vick, please describe the regulation requiring the addition of the SPCC line item (Line Item 1.18).

A. On July 17, 2002 EPA published a revision to Title 40 Code of Regulation Part 112, commonly referred to as the SPCC regulation. As previously explained in my testimony, 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 has assessed its substations to determine which are subject to the revised 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. Gulf expects expenses of $100,000 for this project during the 2004 recovery period.

Q. What O & M activities are included in the Air Quality category?

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

The first, 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 Crist Unit 7 electrostatic precipitator. There are no expenses projected for this project during the 2004 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 $789,874.

The third activity listed on Schedule 2P, 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 2004 is $94,136.

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 and Compliance Assurance Monitoring (CAM) associated with the Clean Air Act Amendment. The expenses expected to occur during the 2004 recovery period for these activities total $488,968.

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 and Surface Water Studies. All of the programs included in Line Item 1.6, General Water Quality, have

been approved in past proceedings. The expenses expected to be incurred during the projection recovery period for these activities total $340,655.

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 $922,143.

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 $42,000 during the projected recovery period.

Finally, Line Item 1.9, Lead and Copper Rule, was also previously approved for ECRC recovery and reflects sampling, analytical and chemical costs related to lead and copper in drinking water. These expenses are expected to total $9,000 during 2004.

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. Ritenour's exhibit. This Line Item refers to the Company's Environmental Audit/Assessment function. This program is an on-going compliance activity previously approved and is expected to incur

$5,000 of expenses during the recovery period.

Q. What O & M activities are included in the 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 an on-going compliance activity previously approved and is projected to incur incremental expenses totaling $209,126.

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?

A. Only one program, Above Ground Storage Tanks (Line Item 1.12), is included in this category. This program is expected to incur $65,000 of expenses during 2004.

Q. Please identify the activities included in the Low NOx (Line Item 1.3) category.

A. This project was for 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 2004 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. There are no expected expenses during the 2004 recovery period. The EPA only mandated that shipments of coal would be analyzed for mercury and chlorine 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.

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 low sulfur coal. There are no projected expenses for the 2004 recovery period.

Q. Please identify the activity included in the Gulf Coast Ozone Study (Line I 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. This will support FDEP's State Implementation Plan (SIP) revisions. This evaluation is considered pre-engineering work necessary to evaluate the most viable, low cost emission control technologies available that may be required to meet the new eight-hour ambient air ozone standard. Expenses for this project during the 2004 recovery period are anticipated to be $20,000.

Q. Please describe the activity included in the SO2 allowances (Line Item 1.19).

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 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 2004 through December 2004?

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
Susan D. Ritenour
Docket No. 030007-EI
Date of Filing: April 1, 2003

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

A. My name is Susan Ritenour. My business address is One Energy Place, Pensacola, Florida 32520. I hold the position of Assistant Secretary and Assistant Treasurer for Gulf Power Company. In this position, I am responsible for supervising the Rates and Regulatory Matters Department.

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

A. I graduated from Wake Forest University in Winston-Salem, North Carolina in 1981 with a Bachelor of Science Degree in Business and from the University of West Florida in 1982 with a Bachelor of Arts Degree in Accounting. I am also a Certified Public Accountant licensed in the State of Florida. I joined Gulf Power Company in 1983 as a Financial Analyst. Prior to assuming my current position, I have held various positions with Gulf including Computer

Modeling Analyst, Senior Financial Analyst, and Supervisor of Rate Services.

My responsibilities 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 prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have.

Counsel: We ask that Ms. Ritenour's Exhibit consisting of 8 schedules be marked as Exhibit No. _____(SDR-1).

Q. Are you familiar with the Environmental Cost Recovery Clause (ECRC) True-up Calculation for the period of January through December 2002 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 2004?

A. An amount to be refunded of $229,600 was calculated which is reflected on Line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $229,600 to be refunded was calculated by taking the difference between the estimated January 2002 through December 2002 over-recovery of $445,767 as approved in Order No. PSC-02-1735-FOF-EI, dated December 10, 2002 and the actual over-recovery of $675,367 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 2002 through December 2002. 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 2002 through December 2002 with the estimated/actual O & M expenses included in the approved estimated true-up filed in conjunction with the November 2002 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 2002 through December 2002 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 2002 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 17 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. Ritenour, does this conclude your testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Susan D. Ritenour
Docket No. 030007-EI
Date of Filing: August 8, 2003

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

A. My name is Susan Ritenour. My business address is One Energy Place, Pensacola, Florida 32520-0780. I hold the position of Assistant Secretary and Assistant Treasurer for Gulf Power Company.

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

A. I graduated from Wake Forest University in Winston-Salem, North Carolina in 1981 with a Bachelor of Science Degree in Business and from the University of West Florida in 1982 with a Bachelor of Arts Degree in Accounting. I am also a Certified Public Accountant licensed in the State of Florida. I joined Gulf Power Company in 1983 as a Financial Analyst. Prior to assuming my current position, I have held various positions with Gulf including Computer Modeling Analyst, Senior Financial Analyst, and Supervisor of Rate Services.

My responsibilities 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 were prepared under my direction, supervision, or review.

Counsel: We ask that Ms. Ritenour's Exhibit consisting of 8 schedules be marked as Exhibit No. _____(SDR-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 2003 through December 2003 period to be refunded or collected in the period January 2004 through December 2004?

A. The estimated true-up for the current period is an over-recovery of $209,163 as shown on Schedule 1E. This is based on six months of actual data and six months of estimated data. This amount will be added to the final true-up over-recovery amount of $229,600 for January 2002 through December 2002 (see Schedule 1A to my testimony filed April 1, 2003) and refunded to the customers during the January 2004 through December 2004 period. The detailed calculations supporting the estimated true-up for 2003 are contained in Schedules 1E through 8E.

Q. Please describe Schedules 2E and 3E of your exhibit.

A. Schedule 2E shows the calculation of the estimated over-recovery of environmental costs for the period January 2003 through December 2003. Schedule 3E of my exhibit is the calculation of the interest provision on the over-recovery. This is the same method of calculating interest that is used in the Fuel Cost Recovery (FCR) and Purchased Power Capacity Cost (PPCC) Recovery clauses.

Q. Please describe Schedules 4E and 5E of your exhibit.

A. Schedule 4E compares the estimated/actual O & M expenses for the period January 2003 through December 2003 with the projected O & M expenses approved by the Commission in conjunction with the November 2002 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 2003 through December 2003 compares the estimated/actual carrying costs related to investment with the projected amount approved in conjunction with the November 2002 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 in his testimony.

Q. Please describe Schedule 8E of your exhibit.

A. Schedule 8E includes 19 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 18 of Schedule 8E show the investment and associated costs related to capital projects, while page 19 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 2003 through December 31, 2003.

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

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Susan D. Ritenour
Docket No. 030007-EI
Date of Filing: September 8, 2003

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

A. My name is Susan Ritenour. My business address is One Energy Place, Pensacola, Florida 32520-0780. I hold the position of Secretary and Treasurer and Regulatory Manager for Gulf Power Company.

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

A. I graduated from Wake Forest University in Winston-Salem, North Carolina in 1981 with a Bachelor of Science Degree in Business and from the University of West Florida in 1982 with a Bachelor of Arts Degree in Accounting. I am also a Certified Public Accountant licensed in the State of Florida. I joined Gulf Power Company in 1983 as a Financial Analyst. Prior to assuming my current position, I have held various positions with Gulf including Assistant Secretary and Assistant Treasurer, Supervisor of Rate Services, Senior Financial Analyst, and Computer Modeling Analyst.

My responsibilities 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 Corporate Secretary and Treasurer 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 2004 through December 2004.

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. Ritenour's Exhibit consisting of 7 schedules be marked as Exhibit No. _____ (SDR-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 2004 through December 2004. 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 2004 through December 2004?

A. The total projected jurisdictional recoverable costs for the period January 2004 through December 2004 are $14,108,217 as shown on line 1c of Schedule 1P. This includes costs related to O & M activities of $2,901,327 and costs related to capital projects of $11,206,890 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 $13,679,296 for the period January 2004 through December 2004 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 $438,763 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 $9,877,198 for the period January 2004 through December 2004 was allocated using the energy allocator, as shown in column 3 on Schedule 7P. The demand-related recoverable revenue requirement of $3,802,098 for the period January 2004 through December 2004 was allocated using the demand allocator, as shown in column 4 on Schedule 7P. The energy-

related and demand-related recoverable revenue requirements are added together to derive the total amount assigned to each rate class, as shown in column 5.

Q. What is the monthly amount related to environmental costs recovered through this factor that will be included on a residential customer's bill for 1,000 kwh?

A. The environmental costs recovered through the clause from the residential customer who uses 1,000 kwh will be $1.36 monthly for the period January 2004 through December 2004.

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

A. The factors will be effective beginning with the first Bill Group for January 2004 and continuing through the last Bill Group for December 2004.

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

A. Yes, it does.

PROGRESS ENERGY FLORIDA

DOCKET NO. 030007-EI

True-Up for the Period
October through December, 2002

DIRECT TESTIMONY OF JAVIER PORTUONDO

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, in the capacity of Manager, Regulatory Services – Florida.

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

A. Yes.

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 of Progress Energy Florida, Inc. ("Progress Energy" or "the Company"), for the period of October 1, 2002 through December 31, 2002. My testimony addresses the

recovery of operating and maintenance ("O&M") costs associated with environmental compliance activities for that period.

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

A. Yes. I am sponsoring Exhibit No. ____ (JP-1), which consists of 5 forms. Form 42-1A reflects the final true-up for the period October 2002 through December 2002. 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. Forms 42-6A, 7A, and 8A are not applicable in this filing as they relate to Capital Investment Projects, of which we have none.

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 Progress Energy. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices, and the provisions of the Uniform System of Accounts prescribed by this Commission.

Q. What is Progress Energy's final net true-up amount for the three-month period October 1, 2002 through December 31, 2002?

A. The final net true-up amount for the three-month period ending December 31, 2002 is an under-recovery of $38,833. This amount is shown on Form 42-1A, Line 3.

Q. Are all costs listed in Forms 42-1A through 42-5A attributable to environmental compliance projects approved by the Commission?

A. Yes, they are.

Q. Has Progress Energy included an interest component for the 2002 under-recovery balance?

A. At Staff's request, Progress Energy has agreed to forego the accrual of interest on the under-recovery during the period prior to the implementation of its initial Environmental Cost Recovery charge in January 2002.

Q. What does the figure of ($25,000) on line 1a of Form 42-4A represent?

A. This figure represents environmental compliance costs for transmission substation O&M expenses that are currently being recovered through Progress Energy's base rates.

Q. How did actual expenditures for October through December, 2002 compare with Progress Energy's estimated/actual projections presented in previous testimony and exhibits?

A. Form 42-4A shows that total O&M project costs were $28,296, or 257.2%, higher than projected. Following are variance explanations for those O&M

projects with significant variances. Individual project variances are provided on Form 42-4A.

Substation Environmental Investigation, Remediation, and Pollution Prevention O&M Expenses: Project expenditures were $9,989 less than anticipated, or a 27.7% variance. Progress Energy did not begin development of the new Environmental Management System components as projected because the Florida Department of Environmental Protection determined that it wanted to establish one set of standards for the state instead of separate regional standards. Establishment of these state-wide standards is expected in early 2003. However, it was necessary to respond to an oil spill at one of the Company's substations.

Distribution System Environmental Investigation, Remediation, and Pollution Prevention O&M Expenses: Project expenditures were $38,285 higher than anticipated, or a 100% variance. Although Progress Energy did not project costs for transformer oil clean-up in the 4th quarter of 2002, several transformer oil leaks occurred that required an immediate response. In addition, the Company was able to begin several other work activities ahead of schedule.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JAVIER PORTUONDO

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 030007-EI

AUGUST 8, 2003

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. What is the scope of your duties?

A. Currently, my responsibilities include management of the regulatory accounting, fuel accounting, and pricing functions and activities for Progress Energy Florida (PEF or "Company").

Q. Please describe your education background and professional experience.

A. I received a Bachelors of Science degree in Accounting from the University of South Florida. I was just recently promoted to Director of Regulatory Services - Florida. My previous position was Manager of PEF's Regulatory Services department for over 7 years. Before then, I held a number of financial and accounting positions within the Controller's department of the Company.

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 2003 through December 2003.

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-1), which consists of 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 2003 through December 2003.

Q. What is the Estimated/Actual True-up amount that PEF is requesting recovery for the period of January 2003 through December 2003?

A. The Estimated/Actual True-up amount for 2003 is an under-recovery of $10,819,500, as shown in Exhibit No. __ (JP-1), 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. Forms 42-2E and 42-3E show the calculation of the ECRC Estimated/Actual True-up amount for the period of January 2003 through December 2003

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

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

On July 28, 2003, PEF filed a Petition for Approval of Environmental Cost Recovery for two new environmental programs, the Pipeline Integrity Management Program (No. 3) and the Above Ground Tank Secondary Containment Program (No. 4). Discussion of these two new programs is included in the testimony of Patricia Q. West.

On July 30th, the Commission assigned Docket No. 030711-EI to the Petition. The Staff Recommendation on this Docket is due September 18th, 2003 and this issue will be addressed at the Agenda Conference on September 30th, 2003. Consistent with the Petition, PEF has included projected O&M costs of $10,000 for the Pipeline Integrity Management Program and capital costs of $18,111 and $9,012 for the Pipeline Integrity Management and the Above Ground Tank Secondary Containment Programs, respectively, for the period of January 2003 through December 2003. This includes only amounts that will be incurred after the date the Petition was filed.

Q. How do the Estimated/Actual project expenditures for January 2003 through December 2003 compare with original projections?

A. Form 42-4E shows that total O&M project costs were $11,329,715 or 276% higher than projected and Form 42-6E shows that we have included capital costs of $27,123 for our two new environmental projects. 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, pages 1 through 3.

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

Project expenditures are estimated to be $473,260, over 800% higher than previously projected. The reasons for this variance are discussed in the testimony of Kent D. Hedrick.

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

Project expenditures are estimated to be $14,970,455 or 267% higher than previously projected. The reasons for this variance are discussed in Kent D. Hedrick's testimony.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JAVIER PORTUONDO

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 030007

AUGUST 8, 2003

(REVISED SEPTEMBER 5, 2003)

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. What is the scope of your duties?

A. Currently, my responsibilities include management of the regulatory accounting, fuel accounting, and pricing functions and activities for Progress Energy Florida (PEF or "Company").

Q. Please describe your education background and professional experience.

A. I received a Bachelors of Science degree in Accounting from the University of South Florida. I was just recently promoted to Director of Regulatory Services - Florida. My previous position was Manager of PEF's Regulatory Services department for over 7 years. Before then, I held a number of financial and accounting positions within the Controller's department of the Company.

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 2003 through December 2003.

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-1), which consists of 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 2003 through December 2003.

Q. What is the Estimated/Actual True-up amount that PEF is requesting recovery for the period of January 2003 through December 2003?

A. The Estimated/Actual True-up amount for 2003 is an under-recovery of $10,820,135, as shown in Exhibit No. ___ (JP-1), 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. Forms 42-2E and 42-3E show the calculation of the ECRC Estimated/Actual True-up amount for the period of January 2003 through December 2003

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

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

On July 28, 2003, PEF filed a Petition for Approval of Environmental Cost Recovery for two new environmental programs, the Pipeline Integrity Management Program (No. 3) and the Above Ground Tank Secondary Containment Program (No. 4). Discussion of these two new programs is included in the testimony of Patricia Q. West.

On July 30th, the Commission assigned Docket No. 030711-EI to the Petition. The Staff Recommendation on this Docket is due September 18th, 2003 and this issue will be addressed at the Agenda Conference on September 30th, 2003. Consistent with the Petition, PEF has included projected O&M costs of $10,000 for the Pipeline Integrity Management Program and capital costs of $18,569 and $9,299 for the Pipeline Integrity Management and the Above Ground Tank Secondary Containment Programs, respectively, for the period of January 2003 through December 2003. This includes only amounts that will be incurred after the date the Petition was filed.

Q. How do the Estimated/Actual project expenditures for January 2003 through December 2003 compare with original projections?

A. Form 42-4E shows that total O&M project costs were $11,329,715 or 276% higher than projected and Form 42-6E shows that we have included capital costs of $27,868 for our two new environmental projects. 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, pages 1 through 3.

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

Project expenditures are estimated to be $473,260, over 800% higher than previously projected. The reasons for this variance are discussed in the testimony of Kent D. Hedrick.

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

Project expenditures are estimated to be $14,970,455 or 267% higher than previously projected. The reasons for this variance are discussed in Kent D. Hedrick's testimony.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JAVIER PORTUONDO

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 030007

AUGUST 8, 2003

(REVISED OCTOBER 17, 2003)

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. What is the scope of your duties?

A. Currently, my responsibilities include management of the regulatory accounting, fuel accounting, and pricing functions and activities for Progress Energy Florida (PEF or "Company").

Q. Please describe your education background and professional experience.

A. I received a Bachelors of Science degree in Accounting from the University of South Florida. I was just recently promoted to Director of Regulatory Services - Florida. My previous position was Manager of PEF's Regulatory Services department for over 7 years. Before then, I held a number of financial and accounting positions within the Controller's department of the Company.

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 2003 through December 2003.

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 2003 through December 2003.

Q. What is the Estimated/Actual True-up amount that PEF is requesting recovery for the period of January 2003 through December 2003?

A. The Estimated/Actual True-up amount for 2003 is an under-recovery of $10,822,944, 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 2003 through December 2003.

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

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

On July 28, 2003, PEF filed a Petition for Approval of Environmental Cost Recovery for two new environmental programs, the Pipeline Integrity Management Program (No. 3) and the Above Ground Tank Secondary Containment Program (No. 4). Discussion of these two new programs is included in the testimony of Patricia Q. West.

On July 30th, the Commission assigned Docket No. 030711-EI to the Petition. The Staff Recommendation on this Docket is due October 22, 2003 and this issue is scheduled to be addressed at the Agenda Conference on November 3, 2003. Consistent with the Petition, PEF has included projected O&M costs of $10,000 for the Pipeline Integrity Management Program and capital costs of $20,686 and $10,423 for the Pipeline Integrity Management and the Above Ground Tank Secondary Containment Programs, respectively, for the period of January 2003 through December 2003. This includes only amounts that will be incurred after the date the Petition was filed.

Q. How do the Estimated/Actual project expenditures for January 2003 through December 2003 compare with original projections?

A. Revised Form 42-4E shows that total O&M project costs were $11,329,715 or 276% higher than projected and revised Form 42-6E shows that we have included capital costs of $31,109 for our two new environmental projects. 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 as revised Form 42-8E, pages 1 through 3.

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

Project expenditures are estimated to be $473,260, over 800% higher than previously projected. The reasons for this variance are discussed in the testimony of Kent D. Hedrick.

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

Project expenditures are estimated to be $14,970,455 or 267% higher than previously projected. The reasons for this variance are discussed in Kent D. Hedrick's testimony.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JAVIER PORTUONDO

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 030007

SEPTEMBER 8, 2003

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. What is the scope of your duties?

A. Currently, my responsibilities include management of the regulatory accounting, fuel accounting, and pricing functions and activities for Progress Energy Florida (PEF or "Company").

Q. Please describe your education background and professional experience.

A. I received a Bachelors of Science degree in Accounting from the University of South Florida. I was just recently promoted to Director of Regulatory Services - Florida. My previous position was Manager of PEF's Regulatory Services department for over 7 years. Before then, I held a number of financial and accounting positions within the Controller's department of the Company.

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 (ECR) factors for application on customer billings during the period January 2004 through December 2004. My testimony addresses the capital and operating and maintenance ("O&M") expenses associated with PEF's environmental compliance activities for the year 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 Exhibit No. (JP-2), 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 2004 through December 2004.

Q. What is the total true-up to be applied in the period January 2004 through December 2004?

A. The total true-up applicable for this period is an under-recovery of $10,858,968. This consists of the final true-up under-recovery of $38,833 for the period from October 1 through December 31, 2002 and an estimated true-up under-recovery of $10,820,135 for the current period of January 2003 through December 2003. The detailed calculation supporting the estimated true-up was provided on ***revised*** Forms 42-1E through 42-8E of Exhibit No. (JP-1) filed with the Commission on September 5, 2003.

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 projects (Nos. 1, 1a, and 2) were previously approved by the Commission in Order No. PSC-02-1735-FOF-EI.

The SO_2 Emissions Allowances 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 were previously

approved in Order No. PSC-95-0450-FOF-EI. We are asking recovery in 2004 for purchases of 27,500 allowances @ $160 for a total of $4,400,000.

On July 28, 2003, PEF filed a Petition for Approval of Environmental Cost Recovery for two new environmental programs, the Pipeline Integrity Management Program (No. 3) and the Above Ground Tank Secondary Containment Program (No. 4). Discussion of these two new programs is included in the testimony of Patricia Q. West.

On July 30th, the Commission assigned Docket No. 030711-EI to the Petition. The Staff Recommendation on this Docket is due September 18th, 2003 and this issue will be addressed at the Agenda Conference on September 30th, 2003. Consistent with the Petition, PEF has included projected O&M costs of $245,000 for the Pipeline Integrity Management Program and no new expenditures for the Above Ground Tank Secondary Containment Programs for the period of January 2004 through December 2004.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2004?

A. Yes. Form 42-3P contained in Exhibit No. JP-2, summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 5, shows the calculations of these costs that result in recoverable jurisdictional capital costs of $61,739.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2004?

A. Yes. Form 42-2P contained in Exhibit No. JP-2, summarizes the recoverable O&M cost estimates for these projects in the amount of $10,165,980.

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 5, contained in Exhibit No. JP-2, provides each project description as well as the projected recoverable cost estimates.

Q. What are the total projected jurisdictional costs for environmental compliance activities in the year 2004?

A. The total jurisdictional capital and O&M costs to be recovered through the ECRC are calculated on Form 42-1P. These costs total $10,227,719.

Q. Please describe how the proposed ECR factors were developed.

A. The ECR factors were calculated as shown on Forms 42-6P and 42-7P of Exhibit JP-2. 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 ECR factors by rate class.

Q. What are Progress Energy Florida's proposed 2004 ECR factors for the various rate groups and delivery voltages?

A. The computation of Progress Energy Florida's proposed ECR factors for customer billings in 2004 is shown on Form 42-7P of Exhibit JP-2. In summary, these factors are as follows:

Rate Class	ECR Factor
Residential	0.061 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.058 cents/kWh
@ Primary Voltage	0.058 cents/kWh
@ Transmission Voltage	0.057 cents/kWh
General Service 100% Load Factor	0.032 cents/kWh
General Service Demand	
@ Secondary Voltage	0.048 cents/kWh
@ Primary Voltage	0.047 cents/kWh
@ Transmission Voltage	0.047 cents/kWh

Curtailable	
@ Secondary Voltage	0.057 cents/kWh
@ Primary Voltage	0.056 cents/kWh
Interruptible	
@ Secondary Voltage	0.037 cents/kWh
@ Primary Voltage	0.037 cents/kWh
@ Transmission Voltage	0.037 cents/kWh
Lighting	0.051 cents/kWh

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

A. PEF is requesting that its proposed ECR factors be made effective beginning with cycle 1 billings for the month of January 2004.

Q. Please summarize your testimony.

A. My testimony supports the approval of an average environmental factor of .054 cents per kWh which includes projected capital and O&M revenue requirements of $10,227,719 associated with a total of 5 environmental projects and a true-up provision of $10,858,968. My testimony also demonstrates that the projected environmental expenditures for 2004 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JAVIER PORTUONDO

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 030007

SEPTEMBER 8, 2003

(REVISED OCTOBER 17, 2003)

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. What is the scope of your duties?

A. Currently, my responsibilities include management of the regulatory accounting, fuel accounting, and pricing functions and activities for Progress Energy Florida (PEF or "Company").

Q. Please describe your education background and professional experience.

A. I received a Bachelors of Science degree in Accounting from the University of South Florida. I was just recently promoted to Director of Regulatory Services - Florida. My previous position was Manager of PEF's Regulatory Services department for over 7 years. Before then, I held a number of financial and accounting positions within the Controller's department of the Company.

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 (ECR) factors for application on customer billings during the period January 2004 through December 2004. My testimony addresses the capital and operating and maintenance ("O&M") expenses associated with PEF's environmental compliance activities for the year 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-3), which consists of revised 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 2004 through December 2004.

Q. What is the total true-up to be applied in the period January 2004 through December 2004?

A. The total true-up applicable for this period is an under-recovery of $10,861,777. This consists of the final true-up under-recovery of $38,833 for the period from October 1 through December 31, 2002 and an estimated true-up under-recovery of $10,822,944 for the current period of January 2003 through December 2003. The detailed calculation supporting the estimated true-up was provided on ***revised*** Forms 42-1E through 42-8E of Exhibit No. __ (JP-2) filed with the Commission on October 17 , 2003.

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 projects (Nos. 1, 1a, and 2) were previously approved by the Commission in Order No. PSC-02-1735-FOF-EI.

The SO_2 Emissions Allowances 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 were previously

approved in Order No. PSC-95-0450-FOF-EI. We are asking recovery in 2004 for purchases of 27,500 allowances @ $160 for a total of $4,400,000.

On July 28, 2003, PEF filed a Petition for Approval of Environmental Cost Recovery for two new environmental programs, the Pipeline Integrity Management Program (No. 3) and the Above Ground Tank Secondary Containment Program (No. 4). Discussion of these two new programs is included in the testimony of Patricia Q. West.

On July 30th, the Commission assigned Docket No. 030711-EI to the Petition. The Staff Recommendation on this Docket is due October 22, 2003 and this issue is scheduled to be addressed at the Agenda Conference on November 3, 2003. Consistent with the Petition, PEF has included projected O&M costs of $245,000 for the Pipeline Integrity Management Program and no new expenditures for the Above Ground Tank Secondary Containment Programs for the period of January 2004 through December 2004.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2004?

A. Yes. Revised Form 42-3P contained in revised Exhibit No. __ JP-3, summarizes the cost estimates projected for these projects. Revised Form 42-4P, pages 1 through 5, shows the calculations of these costs that result in recoverable jurisdictional capital costs of $70,554.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2004?

A. Yes. Revised Form 42-2P contained in revised Exhibit No. __ JP-3, summarizes the recoverable O&M cost estimates for these projects in the amount of $10,165,980.

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

A. Yes. Revised Form 42-5P, pages 1 through 5, contained in revised Exhibit No. ___ JP-3, provides each project description as well as the projected recoverable cost estimates.

Q. What are the total projected jurisdictional costs for environmental compliance activities in the year 2004?

A. The total jurisdictional capital and O&M costs to be recovered through the ECRC are calculated on revised Form 42-1P. These costs total $10,236,534.

Q. Please describe how the proposed ECR factors were developed.

A. The ECR factors were calculated as shown on revised Forms 42-6P and 42-7P of revised 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. Revised Form 42-7P presents the calculation of the proposed ECR factors by rate class.

Q. What are Progress Energy Florida's proposed 2004 ECR factors for the various rate groups and delivery voltages?

A. The computation of Progress Energy Florida's proposed ECRC factors for customer billings in 2004 is shown on revised Form 42-7P of revised Exhibit No. __ JP-3. In summary, these factors are as follows:

Rate Class	ECR Factor
Residential	0.061 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.058 cents/kWh
@ Primary Voltage	0.057 cents/kWh
@ Transmission Voltage	0.057 cents/kWh
General Service 100% Load Factor	0.032 cents/kWh
General Service Demand	
@ Secondary Voltage	0.048 cents/kWh
@ Primary Voltage	0.048 cents/kWh
@ Transmission Voltage	0.047 cents/kWh

Curtailable	
@ Secondary Voltage	0.057 cents/kWh
@ Primary Voltage	0.056 cents/kWh
Interruptible	
@ Secondary Voltage	0.037 cents/kWh
@ Primary Voltage	0.037 cents/kWh
@ Transmission Voltage	0.036 cents/kWh
Lighting	0.051 cents/kWh

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

A. PEF is requesting that its proposed ECR factors be made effective beginning with cycle 1 billings for the month of January 2004.

Q. Please summarize your testimony.

A. My testimony supports the approval of an average environmental factor of .054 cents per kWh which includes projected capital and O&M revenue requirements of $10,236,534 associated with a total of 5 environmental projects and a true-up provision of $10,861,777. My testimony also demonstrates that the projected environmental expenditures for 2004 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

KENT D. HEDRICK

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 030007-EI

AUGUST 8, 2003

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 Supervisor of Environmental Services.

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. I was just recently promoted to Supervisor of Environmental Services. Before then, I held several environmental management positions with the Company.

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 Substation and Distribution System Environmental Investigation, Remediation, and Pollution Prevention Programs for the period January 2003 through December 2003. The Commission approved the Substation and Distribution System Programs last year in response to a new Florida Department of Environmental Protection (DEP) interpretation of its authority to regulate clean up of contaminated soils. *See,* PSC Order No. PSC-02-1735-FOF-EI.

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

A. Yes. I am sponsoring Exhibit No. ___ (KDH-1), which is a short-form consent order that PEF and DEP entered to address investigation and remediation of Substation System sites, and Exhibit No. ___ (KDH-2), which is a Substation Inspection Plan that PEF has submitted in accordance with the DEP consent order.

Q. Please explain the variance between the Estimated/Actual project expenditures and the original projections for the Substation System Program for the period January 2003 to December 2003.

A. Project expenditures for the Substation System Program are estimated to be $423,260 higher than originally projected. This is due primarily to the need to perform DEP-mandated remediation activities that could not be projected at the time of last year's filing, as well as new requirements imposed in a June 2003 DEP consent order that addresses contamination resulting from transformer leaks at the Company's substations.

In last year's filing, PEF included projected costs of $30,000 for development of new components of its Environmental Management System and $20,000 for soil and groundwater investigations at substation sites for the period January 2003 to December 2003. Although there were ongoing DEP investigations at several substation sites, no remediation costs were included in the 2003 projections because neither DEP nor the Company at that time had identified the need for specific remediation activities at substation sites. As a result of detailed assessments required by DEP, however, the Department subsequently required PEF to proceed with remediation activities at six substation sites (Lake Tarpon, Ulmerton, Kenneth City, 40th Street, South Bartow, and Six Mile Creek) during 2003. The assessments and remediation activities at these six substations began in December 2002 and concluded in July 2003. Actual costs of $322,725 for

the site assessment and remediation activities at these six substations has been included in the Estimated/actual cost expenditures for the Substation System Program for the period January 2003 through July 2003.

In addition, since last year's filing, DEP and PEF entered into a short-form consent order addressing transformer leaks at substation sites. (A copy of the consent order is attached as Exhibit ___ (KDH-1)). In accordance with the consent order, the Company has submitted a Substation Inspection Plan calling for inspection of all remaining PEF substation sites (other than the six already remediated) to determine whether soil and/or groundwater remediation is required at those sites. (A copy of the Substation Inspection Plan is attached as Exhibit ___ (KDH-2)). Under the schedule proposed in the Substation Inspection Plan, all inspections are expected to be completed within 180 days from DEP's approval of the Plan. Although DEP has not yet formally approved the Substation Inspection Plan, we expect DEP approval at any time. In the interim, based on discussions with DEP, we are operating under the assumption that all inspections must be completed by December 2003. Accordingly, the Estimated/actual cost expenditures for the period January 2003 to December 2003 include the estimated costs of performing the additional substation inspections at a cost of $200 per station. In addition, the Estimated/Actual cost expenditures include estimated costs for the development of an electronic Environmental Data Management Tracking System as originally contemplated and needed to ensure compliance with the requirements of the consent order.

Q. Please explain the variance between the Estimated/Actual project expenditures for the Distribution System Program and the original projections for the period January 2003 to December 2003.

A. Project expenditures for the Distribution System Program are estimated to be $10,896,455 higher than originally projected. This variance is due to increased estimates of the magnitude and extent of contamination at Distribution System sites, as well as increased cost estimates for associated investigation and remediation activities.

In last year's filing, PEF's cost projections for remediation activities to be performed as part of the Distribution System Program were based on an estimated cost of $1,850 per site. Since that time, PEF has been working with the DEP to finalize the investigation and remediation procedures and criteria for distribution system transformer sites being investigated as part of the Company's ongoing TRIP Program. Rather than address the procedures and criteria separately within each DEP district, the Department has agreed to work with the company to develop a master Environmental Remediation Strategy for the scope of soil and groundwater remediation for the TRIP Program.

In February 2003, PEF submitted a proposed Environmental Remediation Strategy for the TRIP Program. Since that time, the Company and DEP have had continuing discussions regarding the level of cleanup to be required under

the Environmental Remediation Strategy. DEP has not formally approved the Environmental Remediation Strategy, but is expected to do so by September, 2003. Based on our discussions with DEP, PEF anticipates that DEP will, for the first time, require the Company to perform investigation and remediation activities that will result in documented cleanup of all contaminated soils to specific SCTL levels for total recoverable petroleum hydrocarbons (TRPH). We also expect that DEP will require PEF to perform new procedures to detect the presence of lead in the coating used at the distribution system sites and, if lead is present, to document the removal of lead contamination in soils to below the applicable SCTL.

Application of SCTLs to PEF's distribution system sites will require additional sampling procedures and a significantly greater degree of cleanup than had been envisioned at the time the Company sought approval for the Distribution System Program. As a result, the Company now projects a significant increase in the original estimate of the magnitude and extent of contamination, as well as a significant increase in the associated costs of investigation and remediation activities. The unit cost for investigation and remediation activities is now estimated to be $8,500 per site on average, rather than $1,850 per site as originally projected. This increased unit cost is the primary reason for the variance between the original projections and the Estimated/Actual project expenditures for the Distribution System Program.

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

2 A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

KENT D. HEDRICK

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 030007-EI

SEPTEMBER 8, 2003

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 Supervisor of Environmental Services.

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. I was just recently promoted to Supervisor of Environmental Services. Before then, I held several environmental management positions with the Company.

Q. What is the purpose of your testimony?

A. The Commission approved PEF's Substation and Distribution System Investigation, Remediation and Pollution Prevention Programs last year in PSC Order No. PSC-02-1735-FOF-EI. This testimony provides estimates of the costs that will be incurred for these programs in the year 2004.

Q. What costs do you expect to incur in 2004 in connection with the Substation System Investigation, Remediation and Pollution Prevention Program?

A. For 2004, we estimate total O&M expenditures of $754,353 for the Substation System Investigation, Remediation and Pollution Prevention Program for remediation activities at 52 substation sites that are expected to be identified as requiring remediation during 2004. In addition, PEF is continuing to develop pollution prevention measures for substation transformer sites and anticipates seeking recovery of the actual costs of implementing new pollution prevention measures in 2004. At this time, however, PEF is unable to estimate such costs.

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. Current and planned pollution prevention activities also will ensure the level of expenditures is reasonable and prudent since these activities are designed to eliminate the source of the contamination (i.e. leaking mineral oil-filled electrical equipment); thereby minimizing the need for remediation in the future..

Q. What costs do you expect to incur in 2004 in connection with the Distribution System Investigation, Remediation and Pollution Prevention Program?

A. For 2004, we estimate total O&M expenditures of $5,168,353 for the Distribution System Investigation, Remediation and Pollution Prevention Program. These estimated O&M expenditures cover remediation activities at 518 distribution transformer sites. The sites include 498 3-phase transformer sites that have already been identified as requiring remediation and 20 high priority single-phase transformer sites expected to be identified as requiring remediation during ongoing inspections.

Because the Company is only starting to conduct remediation activities at 3-phase transformer sites, remediation costs for those sites are difficult to estimate.

However, the extent and magnitude of contamination is expected to be greater at the 3-phase transformer sites than at single-phase transformer sites because the 3-phase transformers contain a greater volume of oil. As a placeholder, PEF has used an estimated unit remediation cost for the 3-phase transformer sites of approximately $10,000 per site on average. Actual costs could be significantly higher or lower.

The 20 site figure used for high priority single-phase sites is an estimate of the number of sites expected to be identified in 2004 as having a heightened potential environmental impact and, therefore, needing priority attention. Because the results of inspections are difficult to predict, the actual number of these sites could differ substantially from this estimate. The unit remediation cost for these sites is assumed to be $8,500 per site on average.

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

A. The contract pricing for the remediation activities that are a part of the Distribution System Program were established through competitive bidding ensuring they are reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 030007-EI

AUGUST 8, 2003

Q. Please state your name and business address.

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

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

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

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

A. I obtained my B.S. degree in Biology from New College of the University of South Florida in 1983. I was employed by the Polk County Health Department from 1983-1986 and by the Florida Department of Environmental Protection

("DEP") from 1986-1990. At DEP, I was involved in compliance and enforcement efforts associated with petroleum storage facilities. In 1990, I joined Florida Power Corporation as an Environmental Project Manager and then held progressively responsible positions in the company's environmental services department, including the position of team leader for the integration of the environmental functions of Florida Power and Carolina Power and Light. From 2001-2002, I served as Manager of Water Programs in the Environmental Services Section of PEF's Technical Services Department. In 2002, I assumed my current position as Manager of Environmental Programs and Strategy.

Q. What is the purpose of your testimony?

A. My testimony describes two new environmental compliance programs for which Progress Energy is seeking cost recovery in this docket:

- Pipeline Integrity Management Program (No. 3)
- Aboveground Storage Tank Secondary Containment Project (No. 4)

The Company recently filed a petition in Docket No. 030711-EI asking the Commission to determine that the costs of these programs are eligible for recovery through the Environmental Cost Recovery Clause ("ECRC").

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

A. Yes. The general requirements are that all expenditures must have been prudently incurred after April 13, 1993; all activities must be legally required to

comply with a governmentally imposed environmental requirement which was created, or whose effect was triggered, after the company's last test year on which rates are based; and the company must show that none of the expenditures are being recovered through some other cost recovery mechanism or through base rates. In addition, costs are eligible for recovery only if they were incurred after the date of the petition which seeks a determination of eligibility for cost recovery.

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

A. Yes. As discussed in more detail below, each program was implemented in response to a new environmental requirement which was created, or whose effect was triggered, after the minimum filing requirements (MFRs) were submitted in the Company's last rate case, Docket No. 000824-EI. None of the costs of these programs are being recovered through base rates or any other cost recovery mechanism. Although some costs were incurred in connection with the Pipeline Integrity Management Program before the Company filed its petition in Docket No. 030711-EI, we are seeking recovery only of costs incurred after the date that petition was filed.

PIPELINE INTEGRITY MANAGEMENT PROGRAM

Q. Why is the Company implementing the Pipeline Integrity Management Program?

A. PEF is implementing a Pipeline Integrity Management Program in order to comply with the requirements of U.S. Department of Transportation ("USDOT") Regulation 49 CFR Part 195, as amended effective February 15, 2002. A copy of this new regulation, which was published at 67 Federal Register 2136 (January 16, 2002), is attached at Exhibit ___ (PQW-1).

Q. Is this a new regulatory requirement?

A. Yes. Prior to the February 15, 2002 amendments, the USDOT's pipeline integrity management regulations applied only to operators with 500 miles or more of hazardous liquid and carbon dioxide pipelines that could affect high consequence areas. The amendments which became effective on February 15, 2002 extended the requirements for implementing integrity management to operators, such as PEF who have less than 500 miles of regulated pipelines that could affect high consequence areas. Such operators must now develop and implement a pipeline integrity management program that meets the requirements of the regulation. The objective of this regulation is to improve the integrity of pipeline systems in the U.S. in order to protect public safety and the environment. Additionally, the regulation requires continual assessment and evaluation of pipeline integrity through inspection or testing, data integration and analysis, and follow-up remedial, preventative, and mitigative actions.

Q. What facilities does the Company own that are covered by the new regulation?

A. PEF owns one hazardous liquid pipeline that is subject to the new regulation and must comply with the new requirements. That is 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.

Q. What specific activites are required by the new regulation?

A. The new regulation requires PEF to take the following specific actions by the dates indicated:

- November 18, 2002 — Identify each pipeline or pipeline segment that could affect a high consequence area
- February 18, 2003 — Prepare a written integrity management program plan that addresses the risks on each segment of pipeline.
- August 16, 2005 — Conduct an expedited baseline assessment of at least 50% of the pipeline, beginning with the highest risk segment(s).
- February 17, 2009 — Complete the baseline assessment of the entire pipeline.

Q. Has the Company completed the activities that were required by February 18, 2003?

A. Yes. PEF used outside consultants to complete the pipeline identification activity and to prepare the required integrity management program plan. In addition, PEF and its consultants have conducted a Leak Detection Study to determine what modifications are necessary to the Company's existing leak detection system to enable PEF to comply with the on-going monitoring requirements of the new regulations.

These activities were completed prior to the filing of the petition in Docket No. 030711-EI, and the Company has therefore excluded the costs of these activities in calculating the amount for which it is seeking recovery through the ECRC.

Q. Has the Company projected the costs that it will incur for the Pipeline Integrity Management Program in 2003 after the date of filing the petition in Docket No. 030711-EI?

A. We estimate the total project costs for the last half of 2003 to be approximately $990,000 in capital investment and $10,000 in O&M expenses. The capital investment is for the design ($313,690) and implementation ($676,304) of an upgraded leak detection system required to comply with the new regulations. The planned upgrades, which are based on the Leak Detection Study completed in April, 2003, include the acquisition and installation of computer hardware and software for leak detection; modifications to the pipeline system to improve the accuracy, reliability and sensitivity of the existing monitoring and detection system; installation of an additional communications circuit; upgrades to the

Bartow meter station; and related valve and piping work at the Anclote terminus. The O&M expenses include the annual review and update of the integrity management plan and the risk analysis required by the new regulations.

Q. What steps is the Company taking to ensure that the level of expenditures to comply with the new pipeline regulations is reasonable and prudent?

A. Before beginning to implement the upgraded leak detection system, Progress Energy Florida performed a study to identify the most cost-effective method of bringing the system into compliance with the new regulatory requirements.

As future services are required to comply with the regulations, PEF will identify qualified suppliers of the necessary services. Where possible, competitive bidding will be used to select the lowest cost supplier.

Q. Has any other utility obtained approval of a similar program to comply with the new pipeline integrity management rules?

A. Yes, the Commission approved Florida Power and Light Company"s program for compliance with these new regulations in Order No. PSC-02-1735-FOF-EI, issued in Docket No. 020007-EI.

ABOVEGROUND STORAGE TANK SECONDARY CONTAINMENT

Q. Why is the Company proposing to implement aboveground storage tank secondary containment projects?

A. The Company is required to make improvements to many of its aboveground petroleum storage tanks in order to comply with the provisions of Florida Department of Environmental Protection Rule 62-761.510(3). A copy of that rule is attached as Exhibit ____ (PQW-2). 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. It also requires that dike field area secondary containment for pre-1998 tanks be upgraded, if necessary, to meet the requirements of Rule 62-761.500(1)(e).

Q. When is the Company required to comply with this rule?

A. Although Rule 62-761.510(3)(d) has been in place since July 13, 1998, it included a delayed effective date of 2010 for installation of secondary containment for the types of storage tanks operated by PEF, and a delayed effective date of 2005 for upgrade of dike field area secondary containment. Because of these delayed implementation dates, PEF has not previously been required to comply with these provisions. Given the lead time for making the necessary improvements at multiple sites, PEF has just begun the process of upgrading those storage facilities to comply with the rule. This activity is expected is to continue until all tanks are upgraded before the end of 2009.

Q. What facilities does the Company operate that must be upgraded to comply with the rule?

A. We have a total of 12 aboveground storage tanks which must be upgraded to comply with the rule. The number of tanks located at each plant site are as follows:

Bartow (1), Bayboro (2), Avon Park (1), Intercession City (2), Turner (1), DeBary (1), University of Florida (1), Suwannee (1), and Anclote (2)

PEF also has secondary containment systems for concrete dike field areas at its Crystal River Units 1 & 2 and Rio Pinar plant sites which must be upgraded to comply with the new requirements for such systems.

Q. When will these compliance activities take place?

A. The installation of a secondary tank bottom at the Turner plant site, the addition of secondary containment for piping at the Bartow plant, and the upgrade of the dike field secondary containment system at the Crystal River Units 1 & 2 plant site have been scheduled for the second half of 2003. The Company is in the final stages of developing a plan to upgrade the remaining storage tanks to comply with the secondary containment provisions of the rule, and is preparing a timetable to ensure that the required improvements are implemented prior to 2010.

Q. Has the Company projected the costs that it will incur for the Above Ground Secondary Tank Projects in 2003 after the date of filing the petition in Docket No. 030711-EI?

A. We estimate the total project costs for the remainder of 2003 to be approximately $693,800 in capital investment. This includes $502,700 for installation of a secondary tank bottom at the Turner plant site, $91,100 for secondary containment of piping at the Bartow site, and $100,000 for lining or coating the dike field secondary containment at Crystal River Units 1 & 2.

Q. What steps are the Company taking to ensure the level of expenditures to bring the storage tanks and dike field area containment systems into compliance with the new rule is reasonable and prudent?

A. In order to ensure that the costs incurred to comply with the new regulation are prudent and reasonable, PEF is using an outside consultant to identify the tanks and piping that are affected by the secondary containment requirements and to develop a plan to achieve compliance with the rule. Project engineering will be performed by internal personnel or by contractors under blanket contracts. Depending on the particular project, construction of the required improvements will be performed either under blanket site or corporate contracts with contractors who were selected using a competitive bidding process, or by contractors selected by project-specific competitive bids.

Q. Has any other utility obtained approval of any similar programs to comply with DEP secondary containment rules?

A. Yes, the Commission previously approved secondary containment programs for Florida Power and Light Company (FPL) in Order No. PSC-1589-FOF-EI,

Docket No.930661-EI, for Gulf Power Company in Order No. PSC-97-1047-FOF-EI, Docket No. 970007-EI, and for TECO in Order No. PSC-0408-FOF-EI, Docket No. 980007-EI. The FPL, Gulf Power, and TECO programs were required to ensure compliance with rules (17-762 and 62-762) that preceded the current requirements of Rule 62-761, F.A.C., discussed in PEF's petition.

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 2002 through December 2002 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 19, consists of the calculation of depreciation expenses and return on capital investment for each project that is being recovered through the ECRC, and page 20 calculates the return on 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 2002 through December 2002 period?

A. Tampa Electric has calculated and is requesting approval of an over-recovery of $3,000,695 as the actual true-up amount for the January 2002 through December 2002 period.

Q. What is the adjusted net true-up amount which Tampa Electric is requesting for the January 2002 through December 2002 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 $456,568 reflected on Form 42-1A, as the adjusted net true-up amount for the January 2002 through December 2002 period. This adjusted net true-up

amount is the difference between the actual over-recovery and the actual/estimated over-recovery for the January 2002 through December 2002 period as depicted on Form 42-1A. The actual true-up amount for the January 2002 through December 2002 period is an over-recovery of $3,000,695 as compared to the $3,457,263 actual/estimated over-recovery amount approved in FPSC Order No. PSC-02-1735-FOF-EI dated December 10, 2002.

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 2002 through December 2002 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 $6,181,290 or 1.2 percent less than actual/estimated projections. Form 42-6A shows the total capital investment costs were $20,120,446 or 0.1 percent less than actual/estimated projections. O&M and capital

investment projects with material variances are explained below.

O&M Project Variances

- **Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration:** The Big Bend Unit 3 FGD Integration project variance was $346,704 or 20.4 percent less than projected due to unscheduled outages that occurred on Big Bend Unit 3 along with intermittent periods of unit deration. These conditions decreased SO_2 removal that directly resulted in decreased reagent costs.
- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance was $85,795 or 93.5 percent less due to the proceeds from the sale of SO_2 allowances that reduced the actual cost of allowances consumed from the projected amount.
- **Big Bend Units 1 and 2 FGD:** The Big Bend Units 1 and 2 FGD project variance was $307,062 or 8.9 percent greater than projected due to an increase in reagent costs and a decrease in revenue from gypsum sales.
- **Big Bend FGD Optimization and Utilization:** The Big Bend FGD Optimization and Utilization project variance was $38,824 or 7.7 percent greater than projected. This variance was due to increased material and installation

costs associated with the restoration of absorber and quencher piping systems.

- **National Pollutant Discharge Elimination System ("NPDES") Annual Surveillance Fees:** The NPDES Annual Surveillance Fees were $8,433 or 16.2 percent less than projected due to the delay in the 2001 fee assessment for Gannon Station. This assessment was expected in 2002 but by the end of the year it had not been invoiced by the Florida Department of Environmental Protection.
- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study was $6,075 or 14.0 percent greater than projected due to the Florida Department of Environmental Protection's request for a more detailed image of the thermal plume from Gannon Station.

Capital Investment Project Variances

- **Big Bend Particulate Matter ("PM") Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance was $14,763 or 6.9 percent less than projected due to the scheduled work and subsequent invoicing that occurred later in the year than originally planned.
- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project was approved by the Commission in Docket No. 020726, Order No. PSC-02-1445-PAA-EI, issued

October 21, 2002. This approval date precluded the inclusion of an estimate of project expenditures in the Actual/Estimated True-up Filing that was filed on August 9, 2002. Therefore, a variance of $4,280 was incurred as project work commenced during the third quarter of 2002.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

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

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

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

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

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

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

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

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2003 through December 2003 true-up amount to be refunded or recovered in the projection period January 2004 through December 2004. My testimony addresses the recovery of capital and operating and maintenance ("O&M") costs associated with environmental compliance activities for 2003, 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 2004.

Q. Have you prepared an exhibit that shows the determination of the recoverable environmental costs for the period January 2003 through December 2003?

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 2004.

Q. What has Tampa Electric calculated as the estimated true-up for the current period to be applied in the January 2004 through December 2004 ECRC factors?

A. The estimated true-up applicable for the current period, January 2003 through December 2003, is an under-recovery of $163,803. 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 2003 factors?

A. Yes. Tampa Electric is seeking recovery of costs

associated with the Bayside Selective Catalytic Reduction ("SCR") and the Big Bend Unit 4 Separated Overfire Air ("SOFA") Low NO_x Retrofit projects in the estimated true-up filing for 2003.

On December 20, 2002 Tampa Electric filed a petition for approval of cost recovery for its Bayside SCR Consumables project. The Commission approved this project in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI issued April 4, 2003.

Tampa Electric has included the recoverable O&M costs associated with the Bayside SCR Consumables project on Form 42-5E in the estimated true-up filing for 2003. The company does not anticipate capital expenditures for the project.

On March 5, 2003 Tampa Electric filed a petition for approval of cost recovery for its Big Bend Unit 4 SOFA project. The Commission approved this project in Docket No. 030226-EI, Order No. PSC-03-0684-PAA-EI issued June 6, 2003.

Tampa Electric has included the recoverable capital costs associated with Big Bend Unit 4 SOFA project on Form 42-

7E in the estimated true-up filing for 2003. However, Tampa Electric does not anticipate O&M expenditures until the project is operational in early 2004. These O&M expenditures will be addressed in the upcoming 2004 projection filing.

Q. How did the actual/estimated project expenditures for January 2003 through December 2003 period compare with the company's original projection?

A. As shown on Form 42-4E, total O&M activities were $438,656 or 5.3 percent lower than projected costs. Total capital expenditures itemized on Form 42-6E, were $1,174,795 or 5.7 percent higher 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 $400,739 or 15.9 percent lower than originally projected due to a decrease in the cost of consumables, principally water and chemicals, from the original projection.
- **SO_2 Emission Allowances:** The SO_2 Emission Allowances

project variance is estimated to be $257,123 or 194.2 percent lower than originally projected. The variance is due to the unanticipated proceeds from the sale of allowances which created a credit balance that was then applied to the allowances consumed.

- **Big Bend Units 1 and 2 Flue Gas Desulfurization ("FGD"):** The Big Bend Units 1 and 2 FGD project variance is estimated to be $396,001 or 8.9 percent greater than originally projected due to additional contractor maintenance costs than originally projected.
- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance is estimated to be $196,224 or 90.6 percent lower than originally projected due to a delay in the commencement of the sampling plan. The delay stems from ongoing negotiations with the Florida Department of Environmental Protection related to the extent of sampling necessary.
- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project variance is $46,100 or 73.8 percent lower than originally projected. This is due to the limited amount of O&M expense estimated to occur for the balance of 2003 based on the newness of equipment and a greater familiarity with operations subsequent to equipment start-up and initial testing.
- **Bayside SCR Consumables:** The Bayside SCR Consumables

project variance is $66,246 due to the project not being included in the original projection for 2003. As previously stated in my testimony, this project was approved for recovery on April 4, 2003. The 2003 Projection Filing was submitted on September 9, 2002; therefore, the expenditure projection for this project at that time was not possible.

Capital Investment Project Variances

As a result of a recent depreciation study conducted on Tampa Electric assets and subsequently filed with the Commission, the company was authorized to preliminarily apply new depreciation rates to its assets effective January 1, 2003. This decision was rendered in Docket No. 030409-EI, Order No. PSC-03-0736-PCO-EI, issued June 20, 2003. The application of these new rates resulted in small variances to the projects listed below.

- Big Bend Unit 3 Flue Gas Desulfurization Integration
- Big Bend Units 1&2 Flue Gas Conditioning
- Big Bend Unit 4 Continuous Emissions Monitors
- Big Bend Fuel Oil Tank #1 Upgrade
- Big Bend Fuel Oil Tank #2 Upgrade
- Phillips Upgrade Tank #1 for FDEP
- Phillips Upgrade Tank #4 for FDEP
- Big Bend Unit 1 Classifier Replacement

- Big Bend Unit 2 Classifier Replacement
- Big Bend Units 1&2 FGD
- Big Bend Section 114 Mercury Testing Platform
- Big Bend FGD Optimization and Utilization

The timing of the commercial operation of Bayside Power Station Units 1 & 2 in conjunction with the accelerated depreciation of Gannon Station assets created variances for the capital projects listed below.

- Gannon Ignition Oil Tank
- Gannon Unit 5 Classifier Replacement
- Gannon Unit 6 Classifier Replacement
- Gannon Coal Crusher (NO_x Control)

Significant variances for other capital projects are described below.

- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance is estimated to be $35,567 or 4.6 percent lower than the original projection due to a change in the scheduling of unit outages. The work will occur later in the year.
- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance is estimated to be $62,874 or 10.8 percent lower than the original

projection due to a change in the scheduling of unit outages. The work will likely occur at a later date that has yet to be determined. Additionally, lower than anticipated contractor costs have occurred on the project.

- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project variance is estimated to be $189,011 or 57.2 percent lower than the original projection due to the attainment of the July 1, 2003 NO_x emissions limit without the expenditure associated with the originally planned modifications to the main air compressor.
- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance is estimated to be $85,129 due to the project not being included in the original projection for 2003. As previously stated in my testimony, this project was approved for recovery on June 6, 2003. The 2003 Projection Filing was submitted on September 9, 2002; therefore, the expenditure projection for this project at that time was not possible.

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 "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 2004 through December 2004. 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 2004.

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

A. Yes. Exhibit No. ___ (HTB-3), containing one document, was prepared under my direction and supervision. It includes Forms 42-1P through 42-7P that show the calculation and summary of O&M and capital expenditures that support the development of the environmental cost recovery factors for 2004.

Q. What has Tampa Electric calculated as the total true-up to be applied in the period January 2004 through December 2004?

A. The total true-up applicable for this period is an under-recovery of $620,371. This consists of the final true-up under-recovery of $456,568 for the period from January 2002 through December 2002 and an estimated true-up under-recovery of $163,803 for the current period of January 2003 through December 2003. The detailed calculation supporting the estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No. ___ (HTB-2) filed with the Commission on August 8, 2003.

Q. Has Tampa Electric proposed any new environmental compliance projects for ECRC cost recovery for the period from January 2004 through December 2004?

A. Yes. Tampa Electric has proposed two new environmental compliance projects for cost recovery during the January 2004 through December 2004 period. The Bayside SCR Consumables project was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003 and the Big Bend Unit 4 SOFA project was approved by the Commission in Docket No. 030226-EI, Order No. PSC-03-0684-PAA-EI, issued June 6, 2003. A brief description of each project is contained in the direct testimony of Tampa Electric witness Gregory M. Nelson.

Q. What are the capital projects included in the calculation of the ECRC factors for 2004?

A. Tampa Electric proposes to include for ECRC recovery 16 previously approved capital projects and their projected costs in the calculation of the ECRC factors for 2004. 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 2004?

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 16, shows the calculations of these costs that result in recoverable jurisdictional capital costs of $18,008,307.

Q. What are the O&M projects included in the calculation of the ECRC factors for 2004?

A. Tampa Electric proposes to include 12 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2004. 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 FGD Optimization and Utilization, 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 2004?

A. Yes. Form 42-2P contained in Exhibit No. ___ (HTB-3) summarizes the recoverable jurisdictional O&M costs for these projects which total $8,191,759 for 2004.

Q. Do you have a schedule providing the description and progress reports for all environmental compliance activities and projects?

A. Yes. Project descriptions, 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 2004?

A. The total jurisdictional O&M and capital expenditures to

be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $26,200,066.

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 2001 load research study. Form 42-7P presents the calculation of the proposed ECRC factors by rate class.

Q. What are the 2004 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 2004 proposed ECRC billing factors are:

Rate Class	Factor (¢/kWh)
Average Factor	0.143
RS, RST	0.144
GS, GST, TS	0.144
GSD, GSDT	0.143
GSLD, GSLDT, SBF	0.142
IS1, IST1, SBI1, SBIT1, IS3, IST3, SBI3, SBIT3	0.137
SL, OL	0.142

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

A. The environmental cost recovery charge will be effective concurrent with the first billing cycle for January 2004.

Q. Are the costs Tampa Electric is requesting for recovery through the ECRC for the period January 2004 through December 2004 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 0.143 cents per kWh which includes projected capital and O&M revenue requirements of $26,200,066 associated with a total of 20 environmental projects and a true-up under-recovery provision of $620,371. My testimony also explains that the projected environmental expenditures for 2004 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 mailing address is P.O. Box 111, Tampa, Florida 33601, and my business address is 6944 U.S. Highway 41 North, Apollo Beach, Florida 33572. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Director, Environmental Affairs in the Energy Supply Department.

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. My present responsibilities include the management of Tampa Electric's environmental permitting and compliance 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 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 2004 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 as well as the Big Bend Unit 4 Separated Overfire Air ("SOFA") Low NO_x Retrofit that was recently approved in Docket No. 030226-EI. Finally, I will discuss the study that is underway at Big Bend Station which will ultimately identify the direction the company will take to meet the long-term requirements of the CFJ and the CD.

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 further reductions of sulfur dioxide ("SO_2"), NO_x and particulate matter ("PM") emissions at Big Bend Station. The repowering of Gannon Station is projected for completion by early 2004 and will be

renamed Bayside Power Station.

The NO_x reduction activity is ongoing. The Orders require Tampa Electric to perform NO_x reduction projects on Big Bend Units 1 through 3; however, Big Bend Unit 4 may 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 must also demonstrate innovative NO_x technologies beyond those required by the early reduction activities.

Concerning the 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. All of the PM emissions reduction projects are well underway and the work necessary to reduce PM emissions will be largely completed in 2004.

Q. Please describe the Big Bend NO_x Emissions Reduction

program activities and provide the estimated O&M and capital expenditures for 2004.

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 2004, 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 NO_x reduction projects installed in prior years pursuant to the Orders, continuing the DOE neural network sootblowing project on Big Bend Unit 2, and continuing the coal and air-flow monitoring and balancing projects on Big Bend Units 1 and 2. These projects are expected to result in approximately $545,000 of O&M expenses and $437,000 of capital expenditures.

Q. Please describe the Big Bend PM Minimization and Monitoring program activities and provide the estimated O&M and capital expenditures for 2004.

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. For 2004, Tampa Electric has identified various projects that will improve precipitator performance and reduce PM emissions as required under the Orders. These projects include the implementation of the BOP and BACT studies and activities associated with 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 continuing the work on Big Bend Unit 1 slag vent fans and Big Bend Unit 2 flyash controls. These projects are expected to result in approximately $980,000 of O&M expenses and $1.5 million of capital expenditures.

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

A. The programs previously approved by the Commission that I will discuss include Big Bend Unit 3 Flue Gas Desulfurization Integration, Big Bend Units 1 and 2 Flue Gas Desulfurization, Gannon Thermal Discharge Study, Bayside Selective Catalytic Reduction ("SCR") Consumables and Big Bend Unit 4 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 2004.

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 2004, 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 $2.2 million and $4.3 million, respectively. The dominant component of these expenses is projected to be reagents utilized in the flue gas desulfurization 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 2004.

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 2003 with commencement of the work immediately thereafter. For 2004, there will be no capital expenditures for this program; however, Tampa Electric anticipates O&M expenses will be approximately $250,000.

Q. Please describe the Bayside SCR Consumables program activities and provide the estimated O&M and capital expenditures for 2004.

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 2004, 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 $243,000.

Q. 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. Please provide an overview of the environmental compliance requirements associated with the project.

A. The Big Bend Unit 4 SOFA program satisfies two requirements of the Consent Decree. First, an SCR system or other approved NO_x reduction technologies must ultimately be utilized for Big Bend Unit 4 to achieve a NO_x emission rate of 0.10 lbs. per mmBTU by 2007. However, 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. Therefore, the application of SOFA technology at this stage of the company's NO_x abatement effort will reduce the cost of future technologies, such as an SCR system, on Big Bend Unit 4 as Tampa Electric works to achieve the ultimate requirements of the Orders. Second, the application of a SOFA system will be integral to meeting

the requirements of Paragraph 52.C.(1) of the CD which requires Tampa Electric to invest in innovative technologies or otherwise better the NO_x emission limits set forth elsewhere in the CD.

Q. What are the estimated capital and O&M expenditures for 2004 related to the Big Bend Unit 4 SOFA program?

A. For 2004, Tampa Electric anticipates that the capital expenditures for the Big Bend Unit 4 SOFA will be about $575,000 and O&M expenses will be about $50,000.

Q. Please describe the purpose of the study occurring at Big Bend Station and what is expected from the study?

A. The Orders require Big Bend Unit 4 to either 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. The comprehensive study is a wide-ranging evaluation of each of these options relative to the life of Big Bend

Station. Tampa Electric anticipates completing this evaluation no later than the first quarter 2004. After completion of the study, the company will keep the Commission informed of its decision.

Q. Please summarize your testimony.

A. Tampa Electric entered into 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, that the company expects to incur in 2004. Finally, my testimony identified other projects which are required for Tampa Electric to meet environmental requirements and I provided associated 2004 activities and projected expenditures.

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. 030007-EI

August 8, 2003

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present for the Commission's review and approval inclusion of the Manatee Plant in FPL's approved Wastewater/Stormwater Discharge Elimination & Reuse ("WSDER") Project.

Q. Please briefly describe the WSDER Project.

A. The purpose of the WSDER Project is to meet the BMP3 requirements of the NPDES Permits of several FPL plants. The Project eliminates discharges of wastewater and stormwater and beneficially reuses the wastewater and stormwater in plant operations.

Q. Did the Commission approve the WSDER Project in 1998?

A. Yes.

Q. Did the Commission's 1998 approval apply to the Manatee Plant?

A. No. FPL did not petition to include the Manatee Plant in the WSDER Project at that time. When the petition was filed, FPL was seeking certification to burn Orimulsion at the Manatee Plant. As part of the Orimulsion certification, the wastewater and stormwater management issues at Manatee Plant were going to be addressed in the new NPDES permit. Although the Orimulsion certification was later denied, FPL did not amend the 1998 petition to include costs for the Manatee Plant. I advised the Commission Staff during a 1998 deposition that FPL would subsequently petition the Commission if it sought to include costs for the Manatee Plant in the WSDER Project.

Q. Is the scope of the work to meet BMP3 requirements at the Manatee Plant extensive?

A. No. As I explained in 1998, much of the work at the Manatee Plant (such as lining the basins and construction of many of the physical changes required by BMP3) was already performed in connection with

the Orimulsion project. At this time, there are only some minor enhancements needed at the Manatee Plant to be compliant with BMP3 requirements. The work will consist of installing additional piping and vents on the Boiler Blowdown System and the Storm Water Collection System.

Q. Is the scope of the WSDER Project work for the Manatee Plant the same as in 1998?

A. Yes.

Q. When will FPL begin the WSDER Project work at the Manatee Plant?

A. FPL expects to commence the work in October of 2003.

Q. What is FPL's estimated cost for the WSDER Project work at the Manatee Project in 2003?

A. FPL estimates O&M costs of $10,000 in 2003 to meet BMP3 requirements at the Manatee Plant. No costs are anticipated beyond 2003.

Q. Does this conclude your testimony?

A. Yes, it does.

MS. STERN: The staff's stipulations start on Page 15 of the prehearing order, and what we could do is just go ahead and go through the stipulations that are in the prehearing order and make sure that there are no objections to those, and then go back to Gulf's issues and make sure there are no objections to those, if you want to do that.

CHAIRMAN JABER: Well, let me just ask. Are there objections to any of the issues that have proposed stipulations outlined on Page 15 of the prehearing order?

MS. KAUFMAN: Chairman Jaber, there are no objections. I know this would be the case, but I just want the record to be clear that on the issue that is being deferred for next time, the parties will have the opportunity to take whatever position is appropriate.

CHAIRMAN JABER: And just for the record, that was Issue 12A. Does that sound right?

MS. KAUFMAN: Yes, that's correct.

CHAIRMAN JABER: Thank you. Mr. Badders, is it your understanding that with the deferral of that issue from this proceeding that there might be another opportunity for that issue to be resolved in the future?

MR. BADDERS: Yes. It is our intention either in a separate proceeding or in this proceeding next year that that will be addressed.

CHAIRMAN JABER: Staff, do you agree with that?

MS. STERN: That's correct, yes.

CHAIRMAN JABER: Well, won't it be sufficient for us to have one motion that resolves all of the issues and recognize that 12A has been deferred, or do you need something more than that?

MS. KAUFMAN: Yes, there are three generic issues that need to be changed as a result of withdrawing -- I mean, deferring the project, Issue 4, Issue 5, and Issue 8. We have stipulated with all the other utilities on those issues, but not with Gulf because the scrubbers study was outstanding. Now that it is deferred, some of the numbers have changed and we can stipulate with Gulf on those issues.

CHAIRMAN JABER: Issues 1 through 3 are not affected?

MS. STERN: Not affected.

CHAIRMAN JABER: Commissioners, may I have a motion on Issues 1 through 3?

COMMISSIONER DEASON: Move approval of Issues 1 through 3.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: And a second. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: There is a unanimous vote approving the proposed stipulations for Issues 1 through 3. What is the change on Issue 4?

MS. STERN: The change on Issue 4 is that the number for Gulf is 14,101,273.

CHAIRMAN JABER: Commissioners, seeing no objection, how about a motion resolving Issue 4?

COMMISSIONER DEASON: Move approval as modified.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: And a second. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 4 is approved as modified.

Issue 5.

MS. STERN: Issue 5 for Gulf, the true-up amounts for the year 2004, the amount, rather, is 13,672,347.

COMMISSIONER DEASON: Move approval as modified.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 5 is approved as modified. Issues 6 through 7 are not affected, Ms. Stern?

MS. STERN: That's correct.

CHAIRMAN JABER: Commissioners.

COMMISSIONER DEASON: Move approval of 6 and 7.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issues 6 through 7 are resolved. Issue 8, Ms. Stern?

MS. STERN: Yes. Issue 8 is affected on the -- that is the table of cost-recovery factors. The change, there is one change to that table for Rate Class OS-3. The factor will now become .119.

CHAIRMAN JABER: Commissioners, can I have a motion on Issue 8 as modified?

COMMISSIONER DEASON: Move approval as modified.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: And a second. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 8 is approved as modified. There were no objections, right? Are there any modifications to Issues 9 through --

MS. STERN: Nine is the last generic.

CHAIRMAN JABER: Sorry?

MS. STERN: Nine is the last generic issue.

CHAIRMAN JABER: Okay. But are there any modifications for Issues 9 through 13B?

MS. STERN: No.

COMMISSIONER DEASON: 12A is being deferred, correct?

CHAIRMAN JABER: And 12A is being deferred.

COMMISSIONER DEASON: Yes. Move approval of the

remainder of the issues, recognizing 12A is deferred.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: And a second. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Show the rest of the issues approved with the recognition that Issue 12A has been deferred.

MS. KAUFMAN: Chairman Jaber.

CHAIRMAN JABER: Go ahead.

MS. KAUFMAN: I just wanted to clarify with Mr. Badders, there were some e-mails yesterday about a number that needed to be changed from billion to million. Was that correction made?

MR. BADDERS: Is that in the 07 or the 01 docket? I think that is in the 01, the capacity. And there is an error that shows dollars instead of cents.

MS. KAUFMAN: I'm sorry, I'm getting ahead of myself. Thank you.

CHAIRMAN JABER: That's all right. Keep us posted. So, no, this is fine. Anything else to be brought up in the 07 docket, Ms. Stern?

MS. STERN: No, not that I am aware of.

CHAIRMAN JABER: Okay. So that resolves the 07 docket in its entirety. Again, if parties need to leave, you are excused. Let me take an opportunity to acknowledge the

good work of all these parties. Consumer advocates, staff, and, Commissioner Baez, I really appreciate your hard work in pulling this off. Thank you.

* * * * *

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

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

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

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

DATED THIS 24th day of November, 2003.

JANE FAUROT, RPR
Chief, Office of Hearing Reporter Services
FPSC Division of Commission Clerk and
Administrative Services
(850) 413-6732

APPENDIX I

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

JANUARY 2002 - DECEMBER 2002
FINAL TRUE-UP

KMD-1
DOCKET NO. 030007-EI
EXHIBIT_____
PAGES 1-38

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030007-EI EXHIBIT NO. Comp Ex 1
COMPANY/ FP+L
WITNESS: K. M. Dubin, KMD-1, 2pg
DATE: 11-12-03

DOCUMENT NUMBER-DATE
03042 APR-18
FPSC-COMMISSION CLERK

Form 42-1A

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Net True-up for thePeriod
April 15 through December 31, 2002

Line No.				
1	Over/(Under) Recovery for the Current Period (Form 42-2A Page 2 of 2, Line 5)	($7,066,252)		
2	Interest Provision (Form 42-2A Page 2 of 2, Line 6) *	$0		
3	*Total*		($7,066,252)	
4	Estimated/Actual Over/(Under) Recovery for the Same Period **	($7,271,601)		
5	Interest Provision *	*0*		
6	*Total*		($7,271,601)	
7	Net True-Up for the period			$205,349

*In accordance with Order No. PSC-01-2463-FOF-EI no interest is to be calculated on the underrecovery during 2002.

** Per Order No. PSC-02-1735-FOF-EI

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
April 15, 2002 through December 2002

Line No.		April *	May	June
1	ECRC Revenues (net of Revenue Taxes)	$0	$0	$0
2	True-up Provision (Order No. PSC-01-2463-FOF-EI)	0	0	0
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	0	0	0
4	Jurisdictional ECRC Costs			
	a - O&M Activities (Form 42-5A, Line 9)	55,364	101,437	119,124
	b - Capital Investment Projects (Form 42-7A, Line 9)	273,464	509,760	506,670
	c - Total Jurisdictional ECRC Costs	328,828	611,197	625,794
5	Over/(Under) Recovery (Line 3 - Line 4c)	(328,828)	(611,197)	(625,794)
6	Interest Provision (Form 42-3A, Line 10)	0	0	0
7	Beginning Balance True-Up & Interest Provision	0	(328,828)	(940,025)
	a - Deferred True-Up from Jan to Dec 2001 (Form 42-1A, Line 9)	0	0	0
8	True-Up Collected /(Refunded) (See Line 2)	0	0	0
9	*End of Period True-Up (Lines 5+6+7+7a+8)*	(328,828)	(940,025)	(1,565,819)
10	Adjustments to Period Total True-Up Including Interest			
11	End of Period Total True-Up (Lines 9+10)	($328,828)	($940,025)	($1,565,819)

* NOTE: In accordance with Order No. PSC-01-2463-FOF-EI only 16/30 of April's costs are recoverable through the ECRC.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
April 15, 2002 through December 2002

Line No.		July	August	September	October	November	December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$0	$0	$0	$0	$0	$0	$0
2	True-up Provision (Order No. PSC-01-2463-FOF-EI)	0	0	0	0	0	0	0
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	0	0	0	0	0	0	0
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5A, Line 9)	44,693	12,024	70,366	313,695	72,983	2,333,377	3,123,063
	b - Capital Investment Projects (Form 42-7A, Line 9)	504,955	503,393	498,319	499,840	465,767	181,021	3,943,189
	c - Total Jurisdictional ECRC Costs	549,648	515,417	568,685	813,535	538,750	2,514,398	7,066,252
5	Over/(Under) Recovery (Line 3 - Line 4c)	(549,648)	(515,417)	(568,685)	(813,535)	(538,750)	(2,514,398)	(7,066,252)
6	Interest Provision (Form 42-3A, Line 10)	0	0	0	0	0	0	0
7	Beginning Balance True-Up & Interest Provision	(1,565,819)	(2,115,467)	(2,630,884)	(3,199,569)	(4,013,104)	(4,551,854)	0
	a - Deferred True-Up from Jan to Dec 2001 (Form 42-1A, Line 9)	0	0	0	0	0	0	0
8	True-Up Collected /(Refunded) (See Line 2)	0	0	0	0	0	0	0
9	End of Period True-Up (Lines 5+6+7+7a+8)	(2,115,467)	(2,630,884)	(3,199,569)	(4,013,104)	(4,551,854)	(7,066,252)	(7,066,252)
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total True-Up (Lines 9+10)	($2,115,467)	($2,630,884)	($3,199,569)	($4,013,104)	($4,551,854)	($7,066,252)	($7,066,252)

* NOTE: In accordance with Order No. PSC-01-2463-FOF-EI only 16/30 of April's costs are recoverable through the ECRC.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
April 15, 2002 through December 2002

Interest Provision (in Dollars) **

Line No.		April *	May	June
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$0	($328,828)	($940,025)
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	(328,828)	(940,025)	(1,565,819)
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	($328,828)	($1,268,853)	($2,505,844)
4	Average True-Up Amount (Line 3 x 1/2)	($164,414)	($634,427)	($1,252,922)
5	Interest Rate (First Day of Reporting Month)	0.00000%	0.00000%	0.00000%
6	Interest Rate (First Day of Subsequent Month)	0.00000%	0.00000%	0.00000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.00000%	0.00000%	0.00000%
8	Average Interest Rate (Line 7 x 1/2)	0.00000%	0.00000%	0.00000%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.00000%	0.00000%	0.00000%
10	Interest Provision for the Month (Line 4 x Line 9)	$0	$0	$0

** NOTE: In accordance with Order No. PSC-01-2463-FOF-EI no interest is to be calculated on the underrecovery during 2002.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
April 15, 2002 through December 2002

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)	($1,565,819)	($2,115,467)	($2,630,884)	($3,199,569)	($4,013,104)	($4,551,854)	($19,345,550)
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	(2,115,467)	(2,630,884)	(3,199,569)	(4,013,104)	(4,551,854)	(7,066,252)	(26,411,802)
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	($3,681,286)	($4,746,351)	($5,830,453)	($7,212,673)	($8,564,958)	($11,618,106)	($45,757,352)
4	Average True-Up Amount (Line 3 x 1/2)	($1,840,643)	($2,373,176)	($2,915,227)	($3,606,337)	($4,282,479)	($5,809,053)	($22,878,676)
5	Interest Rate (First Day of Reporting Month)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	N/A
6	Interest Rate (First Day of Subsequent Month)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$0	$0	$0	$0	$0	$0	$0

** NOTE: In accordance with Order No. PSC-01-2463-FOF-EI no interest is to be calculated on the underrecovery during 2002.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
April 15, 2002 - December 2002

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	$2,055,638	$2,050,567	$5,071	0.2%
3a	Continuous Emission Monitoring Systems-O&M	$398,640	$287,787	$110,853	38.5%
4a	Clean Closure Equivalency-O&M	$0	$0	$0	0.0%
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	$35,716	$52,160	($16,444)	-31.5%
8a	Oil Spill Cleanup/Response Equipment-O&M	$82,556	$60,482	$22,074	36.5%
13	RCRA Corrective Action-O&M	$66,506	$0	$66,506	N/A
14	NPDES Permit Fees-O&M	$47,500	$43,500	$4,000	9.2%
17a	Disposal of Noncontainerized Liquid Waste-O&M	$179,689	$183,912	($4,223)	-2.3%
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	$753,423	$994,940	($241,517)	-24.3%
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	$453,370	$477,826	($24,456)	-5.1%
19c	Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	($420,174)	($420,174)	$0	0.0%
20	Wastewater Discharge Elimination & Reuse	$0	$0	$0	0.0%
N/A	Amortization of Gains on Sales of Emission Allowances	($503,016)	($490,349)	($12,667)	2.6%
21	St. Lucie Turtle Net	$0	$5,000	($5,000)	N/A
22	Pipeline Integrity Management	$0	$80,000	($80,000)	N/A
2	Total O&M Activities	$3,149,849	$3,325,651	($175,802)	-5.3%
3	Recoverable Costs Allocated to Energy	$2,232,221	$2,112,994	$119,227	5.6%
4a	Recoverable Costs Allocated to CP Demand	$374,291	$427,804	($53,513)	-12.5%
4b	Recoverable Costs Allocated to GCP Demand	$543,336	$784,853	($241,517)	-30.8%

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-02-1735-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
April 15, 2002 - December 2002

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	$0	$0	$0	$ 3,562	$ 6,145	$ 6,145	$ 15,852
3a	Continuous Emission Monitoring Systems-O&M	0	0	0	7,490	20,980	16,204	44,674
4a	Clean Closure Equivalency-O&M	0	0	0	0	0	0	0
5a	Maintenance of Stationary Above Ground Fuel	0	0	0	2,253	3,786	28,766	34,805
	Storage Tanks-O&M	0	0	0				
8a	Oil Spill Cleanup/Response Equipment-O&M	0	0	0	3,115	3,250	6,598	12,963
13	RCRA Corrective Action-O&M	0	0	0	0	0	0	0
14	NPDES Permit Fees-O&M	0	0	0	0	13,500	0	13,500
17a	Disposal of Noncontainerized Liquid Waste-O&M	0	0	0	11,714	2,927	1,591	16,232
19a	Substation Pollutant Discharge Prevention &	0	0	0	51,306	154,037	108,303	313,646
	Removal - Distribution - O&M	0	0	0				
19b	Substation Pollutant Discharge Prevention &	0	0	0	33,030	83,018	41,716	157,765
	Removal - Transmission - O&M	0	0	0				
19c	Substation Pollutant Discharge Prevention &	0	0	0	(46,686)	(46,686)	(46,686)	(140,058)
	Removal - Costs included in Base Rates	0	0	0				
20	Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0
N/A	Amortization of Gains on Sales of Emission Allowances	0	0	0	(10,142)	(139,880)	(43,189)	(193,211)
2	Total of O&M Activities	$0	$0	$0	$ 55,644	$ 101,076	$ 119,448	$ 276,168
3	Recoverable Costs Allocated to Energy	$0	$0	$0	$ 16,485	$ (101,989)	$ (11,238)	$ (96,741)
4a	Recoverable Costs Allocated to CP Demand	$0	$0	$0	$ 11,195	$ 72,371	$ 45,726	$ 129,292
4b	*Recoverable Costs Allocated to GCP Demand*	$0	$0	$0	$ 27,963	$ 130,694	$ 84,960	$243,617
5	Retail Energy Jurisdictional Factor	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%	
6a	Retail CP Demand Jurisdictional Factor	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$0	$0	$0	$16,314	($100,930)	($11,121)	($95,737)
8a	Jurisdictional CP Demand Recoverable Costs (B)	$0	$0	$0	$11,087	$71,673	$45,285	$128,045
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$0	$0	$0	$27,963	$130,694	$84,960	$243,617
9	Total Jurisdictional Recoverable Costs for O&M Activities	$0	$0	$0	$ 55,364	$ 101,437	$ 119,124	$ 275,925

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
April 15, 2002 - December 2002

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	$ 5,785	$ 5,965	$ 5,965	$ 5,965	$ 5,965	$ 2,010,141	$ 2,039,786	$ 2,055,638	-		$ 2,055,638
	3a Continuous Emission Monitoring Systems-O&M	12,094	23,824	19,959	198,151	40,132	59,807	353,966	398,640	-		398,640
	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	339	0	10	562	0	0	911	35,716	35,716		-
	8a Oil Spill Cleanup/Response Equipment-O&M	13,039	2,784	8,358	19,790	742	24,879	69,593	82,556	-		82,556
	13 RCRA Corrective Action-O&M	0	0	0	0	0	66,506	66,506	66,506	66,506		-
	14 *NPDES Permit Fees-O&M*	7,500	7,500	0	0	0	19,000	34,000	47,500	47,500		-
	17a Disposal of Noncontainerized Liquid Waste-O&M	20,050	6,630	0	57,952	14,376	64,450	163,457	179,689			179,689
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	56,934	21,855	67,765	80,808	86,646	125,770	439,777	753,423		753,423	
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	48,478	37,689	62,651	47,236	19,324	80,226	295,606	453,370	418,496		34,875
6	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)	(420,174)	(193,926)	(210,087)	(16,161)
	20 Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0	0	0		
	N/A Amortization of Gains on Sales of Emission Allowances	(72,747)	(47,412)	(47,412)	(47,412)	(47,412)	(47,411)	(309,805)	(503,016)			(503,016)
2	Total of O&M Activities	$ 44,787	$ 12,149	$ 70,610	$ 316,367	$ 73,087	$ 2,356,682	$ 2,873,681	$ 3,149,849	$ 374,291	$ 543,336	$ 2,232,221
3	Recoverable Costs Allocated to Energy	$ (19,846)	$ (7,105)	$ (10,106)	$ 236,284	$ 13,494	$ 2,116,242	$ 2,328,963	$ 2,232,221			
4a	Recoverable Costs Allocated to CP Demand	$ 31,041	$ 20,743	$ 36,295	$ 22,617	$ (3,710)	$ 138,014	$ 244,999	$ 374,291			
4b	Recoverable Costs Allocated to GCP Demand	$ 33,591	$ (1,488)	$ 44,422	$ 57,465	$ 63,303	$ 102,427	$ 299,719	$ 543,336			
5	*Retail Energy Jurisdictional Factor*	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%					
6a	Retail CP Demand Jurisdictional Factor	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	($19,640)	($7,031)	($10,001)	$233,831	$13,354	$2,094,267	$2,304,780	$2,209,043			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$30,742	$20,543	$35,945	$22,399	($3,674)	$136,683	$242,638	$370,683			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$33,591	($1,488)	$44,422	$57,465	$63,303	$102,427	$299,720	$543,337			
9	Total Jurisdictional Recoverable Costs for O&M Activities	$ 44,693	$ 12,024	$ 70,366	$ 313,695	$ 72,983	$ 2,333,377	$ 2,847,138	$ 3,123,063			

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
April 15, 2002 - December 2002

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	$1,559,048	$1,559,050	($2)	0.0%
3b	Continuous Emission Monitoring Systems-Capital	$1,094,670	$1,087,793	$6,877	0.6%
4b	*Clean Closure Equivalency-Capital*	$4,563	$4,561	$2	0.0%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	$1,067,455	$1,096,399	($28,944)	-2.6%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	$2,530	$2,533	($3)	-0.1%
8b	Oil Spill Cleanup/Response Equipment-Capital	$100,139	$102,168	($2,029)	-2.0%
10	Relocate Storm Water Runoff-Capital	$8,751	$8,751	$0	0.0%
NA	SO2 Allowances-Negative Return on Investment	($111,431)	($112,194)	$763	-0.7%
12	Scherer Discharge Pipeline-Capital	$67,190	$67,190	$0	0.0%
17b	Disposal of Noncontainerized Liquid Wate-Capital	$35,710	$35,711	($1)	0.0%
20	Wastewater Discharge Elimination & Reuse	$151,747	$151,746	$1	0.0%
21	St. Lucie Turtle Net	$3,192	$8,957	($5,765)	-64.4%
2	Total Investment Projects-Recoverable Costs	$3,983,562	$4,012,665	$ (29,103)	-0.7%
3	Recoverable Costs Allocated to Energy	$ 2,653,154	$ 2,648,343	$ 4,811	0.2%
4	Recoverable Costs Allocated to Demand	$ 1,330,409	$ 1,364,322	$ (33,913)	-2.5%

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-02-1735-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
April 15, 2002 - December 2002

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	$0	$0	$0	$99,471	$185,605	$184,703	469,779
3b	Continuous Emission Monitoring Systems-Capital	0	0	0	77,110	143,967	143,392	364,469
4b	Clean Closure Equivalency-Capital	0	0	0	290	541	539	1,370
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	0 0	0 0	0 0	82,596	154,634	154,393	391,623
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	0 0	0 0	0 0	161	301	300	761
8b	Oil Spill Cleanup/Response Equipment-Capital	0	0	0	6,059	11,296	11,232	28,587
10	Relocate Storm Water Runoff-Capital	0	0	0	553	1,034	1,031	2,618
NA	SO2 Allowances-Negative Return on Investment	0	0	0	(6,317)	(12,928)	(14,152)	(33,397)
12	Scherer Discharge Pipeline-Capital	0	0	0	4,254	7,952	7,928	20,134
17	Disposal of NonContainerized Liquid Waste-Capital	0	0	0	2,476	4,612	4,581	11,669
20	Wastewater Discharge Elimination and Reuse	0	0	0	9,606	17,958	17,903	45,468
21	St. Lucie Turtle Net	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$0	$0	$0	$276,259	$514,971	$511,849	$1,303,080
3	Recoverable Costs Allocated to Energy	$0	$0	$0	$178,417	$331,900	$329,166	$ 839,483
4	Recoverable Costs Allocated to Demand	$0	$0	$0	$97,842	$183,071	$182,683	$ 463,597
5	Retail Energy Jurisdictional Factor	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%	
6	Retail Demand Jurisdictional Factor	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	
7	Jurisdictional Energy Recoverable Costs (B)	$0	$0	$0	$ 176,565	$ 328,453	$ 325,748	$ 830,766
8	Jurisdictional Demand Recoverable Costs (C)	$0	$0	$0	$ 96,899	$ 181,307	$ 180,922	$ 459,128
9	Total Jurisdictional Recoverable Costs for Investment Projects	$0	$0	$0	$ 273,464	$ 509,760	$ 506,670	$ 1,289,894

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
April 15, 2002 - December 2002

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	$183,801	$182,898	$181,996	$181,094	$180,192	$179,289	$1,089,269	$1,559,048	-	$1,559,048
3b	Continuous Emission Monitoring Systems-Capital	142,817	142,155	137,983	140,524	138,329	28,392	$730,201	$1,094,670	-	1,094,670
4b	Clean Closure Equivalency-Capital	537	535	533	531	529	527	$3,193	$4,563	4,212	351
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	154,152	153,848	153,542	153,237	120,027	(58,974)	$675,832	$1,067,455	985,343	82,112
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	298	297	296	295	293	292	$1,769	$2,530	2,336	195
8b	Oil Spill Cleanup/Response Equipment-Capital	11,168	11,157	11,146	11,082	15,537	11,462	$71,552	$100,139	92,436	7,703
10	Relocate Storm Water Runoff-Capital	1,029	1,026	1,023	1,021	1,018	1,016	$6,133	$8,751	8,078	673
NA	SO2 Allowances-Negative Return on Investment	(13,989)	(13,572)	(13,191)	(12,809)	(12,427)	(12,046)	($78,034)	($111,431)		(111,431)
12	Scherer Discharge Pipeline-Capital	7,904	7,879	7,855	7,830	7,806	7,782	$47,056	$67,190	62,021	5,168
17	Disposal of Noncontainerized Liquid Waste-Capital	4,550	4,520	4,489	4,458	1,604	4,420	$24,041	$35,710	32,963	2,747
20	Wastewater Discharge Elimination and Reuse	17,849	17,795	17,740	17,686	17,632	17,577	$106,279	$151,747	140,074	11,673
21	St. Lucie Turtle Net	0	0	0	0	0	3,192	$3,192	$3,192	2,946	246
2	Total Investment Projects - Recoverable Costs	$ 510,116	$ 508,538	$ 503,411	$ 504,949	$ 470,540	$ 182,929	$ 2,680,483	$ 3,983,562	$ 1,330,409	$ 2,653,154
3	Recoverable Costs Allocated to Energy	$ 327,820	$ 326,639	$ 321,912	$ 323,897	$ 318,744	$ 194,657	$ 1,813,670	$ 2,653,154		
4	Recoverable Costs Allocated to Demand	$ 182,295	$ 181,899	$ 181,499	$ 181,052	$ 151,796	$ (11,728)	$ 866,812	$ 1,330,409		
5	Retail Energy Jurisdictional Factor	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%	98.96163%				
6	Retail Demand Jurisdictional Factor	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%				
7	Jurisdictional Energy Recoverable Costs (B)	$ 324,416	$ 323,247	$ 318,570	$ 320,534	$ 315,434	$ 192,636	$ 1,794,838	$ 2,625,604		
8	Jurisdictional Demand Recoverable Costs (C)	$ 180,538	$ 180,145	$ 179,749	$ 179,307	$ 150,332	$ (11,615)	$ 858,456	$ 1,317,584		
9	Total Jurisdictional Recoverable Costs for Investment Projects	$ 504,955	$ 503,393	$ 498,319	$ 499,840	$ 465,767	$ 181,021	$ 2,653,294	$ 3,943,188		

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 2002

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)	7,974,043	8,086,134	8,198,226	8,310,318	8,422,410	8,534,502	8,646,593	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$9,637,425	$9,525,334	$9,413,242	$9,301,150	$9,189,058	$9,076,966	$8,964,875	n/a
6.	Average Net Investment		9,581,380	9,469,288	9,357,196	9,245,104	9,133,012	9,020,920	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		56,785	56,121	55,456	54,792	54,128	53,463	330,745
	b. Debt Component (Line 6 x 2.5471% x 1/12)		20,337	20,099	19,861	19,624	19,386	19,148	118,455
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)		$189,214	$188,312	$187,410	$186,507	$185,605	$184,703	$1,121,751

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

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)	8,646,593	8,758,685	8,870,777	8,982,869	9,094,961	9,207,053	9,319,144	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$8,964,875	$8,852,783	$8,740,691	$8,628,599	$8,516,507	$8,404,415	$8,292,324	n/a
6.	Average Net Investment		8,908,829	8,796,737	8,684,645	8,572,553	8,460,461	8,348,370	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		52,799	52,135	51,470	50,806	50,142	49,477	637,575
	b. Debt Component (Line 6 x 2.5471% x 1/12)		18,910	18,672	18,434	18,196	17,958	17,720	228,344
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)		$183,801	$182,898	$181,996	$181,094	$180,192	$179,289	$2,211,021

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

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		$44	$4,310	$5,294	($7,267)		$0	$2,380
	c. Retirements				$1,946,624	$5,718		$16,321	$1,968,663
	d. Other (A)					$1,923			$1,923
2.	Plant-In-Service/Depreciation Base (B)	$14,961,390	14,961,434	14,965,743	13,024,413	13,011,428	13,011,428	12,995,106	0
3.	Less: Accumulated Depreciation (C)	5,183,308	5,257,914	5,332,532	3,336,898	3,396,151	3,462,993	3,513,475	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$9,778,082	$9,703,520	$9,633,211	$9,687,515	$9,615,276	$9,548,435	$9,481,631	n/a
6.	*Average Net Investment*		9,740,801	9,668,365	9,660,363	9,651,396	9,581,856	9,515,033	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		57,730	57,301	57,253	57,200	56,788	56,392	342,663
	b. Debt Component (Line 6 x 2.5471% x 1/12)		20,676	20,522	20,505	20,486	20,338	20,196	122,723
8.	Investment Expenses								
	a. Depreciation (E)		74,606	74,618	(49,010)	66,895	66,841	66,804	300,754
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$153,012	$152,440	$28,748	$144,580	$143,967	$143,392	$766,140

Notes:

(A) Cost of removal at Manatee Units 1 and 2.
(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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

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			$265	$3,042				$5,687
	c. Retirements			$49,973	$390,798				$2,409,434
	d. Other (A)							($1,335,087)	($1,333,164)
2.	Plant-In-Service/Depreciation Base (B)	$12,995,106	12,995,106	12,945,398	12,557,643	12,557,643	12,557,643	12,557,643	n/a
3.	Less: Accumulated Depreciation (C)	3,513,475	3,580,242	3,596,909	3,269,088	3,335,112	3,399,467	4,800,702	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$9,481,631	$9,414,865	$9,348,489	$9,288,555	$9,222,530	$9,158,176	$7,756,940	n/a
6.	Average Net Investment		9,448,248	9,381,677	9,318,522	9,255,542	9,190,353	8,457,558	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		55,996	55,601	55,227	54,854	54,468	50,125	668,934
	b. Debt Component (Line 6 x 2.5471% x 1/12)		20,055	19,913	19,779	19,646	19,507	17,952	239,575
	c. Adjustment to reduce return March to December (A).							(86,326)	(86,326)
8.	Investment Expenses								
	a. Depreciation (E)		66,766	66,640	62,977	66,024	64,354	66,149	693,665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)							(19,507)	(19,507)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$142,817	$142,155	$137,983	$140,524	$138,329	$28,392	$1,496,340

Notes:

(A) Adjustment to move negative balance in accumulated depreciation reserve related to the Ft. Myers and Sanford asset retirements recorded in March 2002 to base.
(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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) Depreciation offset in accordance with page 7 of Order No. PSC-2513-FOF-EI.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

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)	20,950	21,194	21,439	21,683	21,927	22,172	22,416	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$37,916	$37,672	$37,427	$37,183	$36,939	$36,694	$36,450	n/a
6.	Average Net Investment		37,794	37,550	37,305	37,061	36,817	36,572	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		224	223	221	220	218	217	1,322
	b. Debt Component (Line 6 x 2.5471% x 1/12)		80	80	79	79	78	78	474
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)		$549	$547	$545	$543	$541	$539	$3,264

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

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)	22,416	22,660	22,905	23,149	23,393	23,638	23,882	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$36,450	$36,206	$35,961	$35,717	$35,473	$35,228	$34,984	n/a
6.	Average Net Investment		36,328	36,084	35,839	35,595	35,351	35,106	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		215	214	212	211	210	208	2,592
	b. Debt Component (Line 6 x 2.5471% x 1/12)		77	77	76	76	75	75	928
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)		$537	$535	$533	$531	$529	$527	$6,456

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

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		$212,601	$221,881	($4)				$434,478
	c. Retirements				$3,404,519				$3,404,519
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$15,630,479	15,843,080	16,064,961	12,660,438	12,660,438	12,660,438	12,660,438	n/a
3.	Less: Accumulated Depreciation (C)	1,522,480	1,565,911	1,610,177	(1,918,889)	(1,881,221)	(1,843,484)	(1,805,683)	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$14,107,999	$14,277,169	$14,454,784	$14,579,327	$14,541,659	$14,503,922	$14,466,121	n/a
6.	Average Net Investment		14,192,584	14,365,977	14,517,055	14,560,493	14,522,790	14,485,021	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		84,114	85,141	86,037	86,294	86,071	85,847	513,504
	b. Debt Component (Line 6 x 2.5471% x 1/12)		30,125	30,493	30,814	30,906	30,826	30,746	183,909
8.	Investment Expenses								
	a. Depreciation (E)		43,431	44,266	(124,547)	37,668	37,737	37,801	76,356
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$157,670	$159,901	($7,696)	$154,868	$154,634	$154,393	$773,770

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

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	$0	$0	$434,478
	c. Retirements				$237,306				$3,641,825
	d. Other (A)							($3,073,713)	($3,073,713)
2.	Plant-In-Service/Depreciation Base (B)	$12,660,438	12,660,438	12,660,438	12,423,132	12,423,132	12,423,132	12,423,132	n/a
3.	Less: Accumulated Depreciation (C)	(1,805,683)	(1,767,819)	(1,729,955)	(1,929,397)	(1,891,534)	(1,886,709)	1,224,118	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$14,466,121	$14,428,257	$14,390,392	$14,352,529	$14,314,666	$14,309,841	$11,199,014	n/a
6.	Average Net Investment		14,447,189	14,409,325	14,371,461	14,333,598	14,312,254	12,754,428	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		85,623	85,398	85,174	84,950	84,823	75,590	1,015,062
	b. Debt Component (Line 6 x 2.5471% x 1/12)		30,665	30,585	30,505	30,424	30,379	27,072	363,539
	c. Adjustment to reduce return March to December.(A)							(198,751)	(198,751)
8.	Investment Expenses								
	a. Depreciation (E)		37,864	37,864	37,864	37,863	31,594	37,114	296,520
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)						(26,770)		(26,770)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$154,152	$153,848	$153,542	$153,237	$120,027	($58,974)	$1,449,602

Notes:

(A) Adjustment to Return resulting from moving the negative balance in accumulated depreciation reserve related to the Ft. Myers and Sanford asset retirements recorded in March 2002 to base.
(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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) Adjustment to correct depreciation expense for Work Order No. 5367/70/913/06 from 1994 to end of 2002. A retirement made in 1994 was not removed from the depreciation calculation, causing excess depreciation to be calculated.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

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)	11,934	12,086	12,239	12,392	12,544	12,697	12,849	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$19,096	$18,944	$18,791	$18,639	$18,486	$18,333	$18,181	n/a
6.	Average Net Investment		19,020	18,867	18,715	18,562	18,410	18,257	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		113	112	111	110	109	108	663
	b. Debt Component (Line 6 x 2.5471% x 1/12)		40	40	40	39	39	39	237
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)		$306	$304	$303	$302	$301	$300	$1,816

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

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)	12,849	13,002	13,154	13,307	13,459	13,612	13,765	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$18,181	$18,028	$17,876	$17,723	$17,571	$17,418	$17,265	n/a
6.	Average Net Investment		18,105	17,952	17,799	17,647	17,494	17,342	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		107	106	105	105	104	103	1,293
	b. Debt Component (Line 6 x 2.5471% x 1/12)		38	38	38	37	37	37	463
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)		$298	$297	$296	$295	$293	$292	$3,587

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

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	$0	$0	$0	$0	$0
	c. Retirements				$3,907				
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$719,530	719,530	719,530	715,623	715,623	715,623	715,623	n/a
3.	Less: Accumulated Depreciation (C)	268,756	276,712	284,668	288,716	296,672	304,628	312,584	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$450,774	$442,818	$434,863	$426,907	$418,951	$410,995	$403,039	n/a
6.	Average Net Investment		446,796	438,841	430,885	422,929	414,973	407,017	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,648	2,601	2,554	2,507	2,459	2,412	15,181
	b. Debt Component (Line 6 x 2.5471% x 1/12)		948	931	915	898	881	864	5,437
8.	Investment Expenses								
	a. Depreciation (E)		7,956	7,956	7,956	7,956	7,956	7,956	47,735
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,552	$11,488	$11,424	$11,360	$11,296	$11,232	$68,352

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

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		$0	$5,368	$0	$0	$5,095	$0	$10,463
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$715,623	715,623	720,992	720,992	720,992	726,086	726,086	n/a
3.	Less: Accumulated Depreciation (C)	312,584	320,540	328,527	336,547	344,567	357,104	365,630	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$403,039	$395,084	$392,464	$384,444	$376,425	$368,982	$360,456	n/a
6.	Average Net Investment		399,061	393,774	388,454	380,435	372,703	364,719	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,365	2,334	2,302	2,255	2,209	2,162	28,807
	b. Debt Component (Line 6 x 2.5471% x 1/12)		847	836	825	808	791	774	10,317
8.	Investment Expenses								
	a. Depreciation (E)		7,956	7,988	8,020	8,020	8,526	8,526	96,770
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)						4,011		4,011
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,168	$11,157	$11,146	$11,082	$15,537	$11,462	$139,904

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) Correction due to incorrect amortization formula being used for amortization of 5 and 7 year property in 2002.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

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)	26,997	27,312	27,626	27,940	28,254	28,568	28,882	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$90,797	$90,482	$90,168	$89,854	$89,540	$89,226	$88,912	n/a
6.	Average Net Investment		90,639	90,325	90,011	89,697	89,383	89,069	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		537	535	533	532	530	528	3,195
	b. Debt Component (Line 6 x 2.5471% x 1/12)		192	192	191	190	190	189	1,144
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)		$1,044	$1,041	$1,039	$1,036	$1,034	$1,031	$6,225

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

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)	28,882	29,196	29,510	29,824	30,139	30,453	30,767	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$88,912	$88,598	$88,284	$87,970	$87,655	$87,341	$87,027	n/a
6.	Average Net Investment		88,755	88,441	88,127	87,812	87,498	87,184	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		526	524	522	520	519	517	6,323
	b. Debt Component (Line 6 x 2.5471% x 1/12)		188	188	187	186	186	185	2,265
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)		$1,029	$1,026	$1,023	$1,021	$1,018	$1,016	$12,358

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

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)	238,961	241,990	245,019	248,048	251,077	254,106	257,134	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$625,299	$622,270	$619,241	$616,212	$613,183	$610,154	$607,126	n/a
6.	Average Net Investment		623,785	620,756	617,727	614,698	611,669	608,640	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,697	3,679	3,661	3,643	3,625	3,607	21,912
	b. Debt Component (Line 6 x 2.5471% x 1/12)		1,324	1,318	1,311	1,305	1,298	1,292	7,848
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)		$8,050	$8,025	$8,001	$7,977	$7,952	$7,928	$47,933

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

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)	257,134	260,163	263,192	266,221	269,250	272,279	275,308	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$607,126	$604,097	$601,068	$598,039	$595,010	$591,981	$588,952	n/a
6.	Average Net Investment		605,611	602,582	599,553	596,524	593,496	590,467	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,589	3,571	3,553	3,535	3,517	3,499	43,178
	b. Debt Component (Line 6 x 2.5471% x 1/12)		1,285	1,279	1,273	1,266	1,260	1,253	15,464
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)		$7,904	$7,879	$7,855	$7,830	$7,806	$7,782	$94,989

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

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)	195,425	199,245	203,065	206,885	210,705	214,525	218,345	n/a
4.	*CWIP - Non Interest Bearing*	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$115,584	$111,764	$107,944	$104,124	$100,304	$96,484	$92,664	n/a
6.	Average Net Investment		113,674	109,854	106,034	102,214	98,394	94,574	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		674	651	628	606	583	561	3,703
	b. Debt Component (Line 6 x 2.5471% x 1/12)		241	233	225	217	209	201	1,326
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)		$4,735	$4,704	$4,673	$4,643	$4,612	$4,581	$27,948

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

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)	218,345	222,164	225,984	229,804	233,624	234,609	238,429	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$92,664	$88,845	$85,025	$81,205	$77,385	$76,400	$72,580	n/a
6.	Average Net Investment		90,755	86,935	83,115	79,295	76,892	74,490	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		538	515	493	470	456	441	6,615
	b. Debt Component (Line 6 x 2.5471% x 1/12)		193	185	176	168	163	158	2,369
8.	Investment Expenses								
	a. Depreciation (E)		3,820	3,820	3,820	3,820	3,820	3,820	45,840
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)						(2,835)		(2,835)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,550	$4,520	$4,489	$4,458	$1,604	$4,420	$51,989

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) Adjustment for timing error in recording effect of change to amortization.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

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)	141,111	147,860	154,609	161,358	168,107	174,856	181,605	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,422,884	$1,416,135	$1,409,386	$1,402,637	$1,395,888	$1,389,139	$1,382,390	n/a
6.	*Average Net Investment*		1,419,510	1,412,761	1,406,012	1,399,263	1,392,514	1,385,765	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		8,413	8,373	8,333	8,293	8,253	8,213	49,877
	b. Debt Component (Line 6 x 2.5471% x 1/12)		3,013	2,999	2,984	2,970	2,956	2,941	17,863
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)		$18,175	$18,121	$18,066	$18,012	$17,958	$17,903	$108,235

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

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)	$181,605	188,354	195,103	201,852	208,601	215,350	222,099	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,382,390	$1,375,641	$1,368,892	$1,362,143	$1,355,394	$1,348,645	$1,341,896	n/a
6.	Average Net Investment		1,379,016	1,372,266	1,365,517	1,358,768	1,352,019	1,345,270	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		8,173	8,133	8,093	8,053	8,013	7,973	98,315
	b. Debt Component (Line 6 x 2.5471% x 1/12)		2,927	2,913	2,898	2,884	2,870	2,855	35,211
8.	Investment Expenses								
	a. Depreciation (E)		6,749	6,749	6,749	6,749	6,749	6,749	80,988
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$17,849	$17,795	$17,740	$17,686	$17,632	$17,577	$214,514

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: St. Lucie 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	$732,120	$732,120
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	732,120	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	976	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	$731,143	n/a
6.	Average Net Investment		0	0	0	0	0	365,572	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	2,167	2,167
	b. Debt Component (Line 6 x 2.5471% x 1/12)		0	0	0	0	0	776	776
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	976	976
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)							(727)	(727)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$3,192	$3,192

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 24-26.
(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 a 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 24-26.
(F) Applicable amortization period(s). See Form 42-8A, pages 24-26.
(G) Depreciation offset in accordance with page 7 of Order No. PSC-2513-FOF-EI.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2002

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	(1,538,080)	(1,519,063)	(1,500,047)	(1,481,031)	(1,462,015)	(1,750,340)	(1,765,960)		
2	Total Working Capital	($1,538,080)	($1,519,063)	($1,500,047)	($1,481,031)	($1,462,015)	($1,750,340)	($1,765,960)		
3	Average Net Working Capital Balance		(1,528,571)	(1,509,555)	(1,490,539)	(1,471,523)	(1,606,177)	(1,758,150)		
4	Return on Average Net Working Capital Balance									
	a *Equity Component grossed up for taxes* (A)		(9,059)	(8,947)	(8,834)	(8,721)	(9,519)	(10,420)	(55,500)	
	b Debt Component (Line 3 x 2.5471% x 1/12)		(3,245)	(3,204)	(3,164)	(3,123)	(3,409)	(3,732)	(19,877)	
5	Total Return Component		($12,304)	($12,151)	($11,998)	($11,845)	($12,928)	($14,152)	($75,377)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(19,016)	(19,016)	(19,016)	(19,016)	(139,880)	(43,189)	(259,134)	
	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)		($19,016)	($19,016)	($19,016)	($19,016)	($139,880)	($43,189)	($259,134)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(31,320)	(31,167)	(31,014)	(30,861)	(152,809)	(57,341)		
	a Recoverable Costs Allocated to Energy		(31,320)	(31,167)	(31,014)	(30,861)	(152,809)	(57,341)		
	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)		(30,862)	(30,711)	(30,560)	(30,410)	(150,574)	(56,502)	(329,619)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($30,862)	($30,711)	($30,560)	($30,410)	($150,574)	($56,502)	($329,619)	

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 a 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 2002

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	(1,765,960)	(1,709,866)	(1,662,455)	(1,615,043)	(1,567,632)	(1,520,220)	(1,472,809)		
2	Total Working Capital	($1,765,960)	($1,709,866)	($1,662,455)	($1,615,043)	($1,567,632)	($1,520,220)	($1,472,809)		
3	Average Net Working Capital Balance		(1,737,913)	(1,686,161)	(1,638,749)	(1,591,337)	(1,543,926)	(1,496,514)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(10,300)	(9,993)	(9,712)	(9,431)	(9,150)	(8,869)	(112,956)	
	b Debt Component (Line 6 x 2.5471% x 1/12)		(3,689)	(3,579)	(3,478)	(3,378)	(3,277)	(3,176)	(40,455)	
5	Total Return Component		($13,989)	($13,572)	($13,191)	($12,809)	($12,427)	($12,046)	($153,410)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(72,747)	(47,412)	(47,412)	(47,412)	(47,412)	(47,411)	(568,939)	
	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)		($72,747)	($47,412)	($47,412)	($47,412)	($47,412)	($47,411)	($568,939)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		($86,736)	($60,984)	($60,602)	($60,221)	($59,839)	($59,457)		
	a Recoverable Costs Allocated to Energy		(86,736)	(60,984)	(60,602)	(60,221)	(59,839)	(59,457)		
	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)		(85,467)	(60,092)	(59,716)	(59,340)	(58,964)	(58,587)	(711,786)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($85,467)	($60,092)	($59,716)	($59,340)	($58,964)	($58,587)	($711,786)	

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 a 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 2002

Project No.	PLANT NAME	PLANT ACCOUNT	DEPRECIATION RATE/ AMORTIZATION PERIOD	APRIL PLANT IN SERVICE (EOM)	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	$ 623,737.24
	MARTIN COM PPBT	316	5yr	$ 15,228.31	$ 15,228.31
	MARTIN COM PPBT	316	7yr	$ 53,549.84	$ 53,549.84
	SANFORD	316	7yr		$ 5,094.50
	TURKEY COMMON	316	7yr		$ 5,368.46
	TOTAL FOR PROJECT 8			**715,622.71**	**726,085.67**
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%	**$0.00**	**$732,120.00**

PROJECT NO 3 b

PLANT NAME	PLANT ACCOUNT	DEPRECIATION RATE/ AMORTIZATION PERIOD	FOR 2002 APRIL PLANT IN SERVICE (EOM)	DECEMBER PLANT IN SERVICE (EOM)
PUTNAM COMMON	341	4.20%	$ 82,857.82	$ 82,857.82
PUTNAM UNIT 1	343	6.00%	$ 334,006.31	$ 330,024.01
PUTNAM UNIT 2	343	6.30%	$ 342,873.31	$ 342,873.31
SANFORD COMMON	312	3.50%	$ -	$ -
SANFORD UNIT 3	311	2.40%	$ 54,282.08	$ 54,282.08
SANFORD UNIT 3	312	2.40%	$ 72,986.22	$ 76,028.32
SANFORD UNIT 3 RL	312	0.00%	$ 449,869.77	$ 447,259.15
SANFORD UNIT 4	312	2.60%	$ 17,124.70	$ -
SANFORD UNIT 4 RL	312	0.00%	$ 331,728.50	$ 41,859.48
SANFORD UNIT 5	311	2.70%	$ (2,869.78)	$ -
SANFORD UNIT 5	312	4.20%	$ 19,191.13	$ -
CAPE CANAVERAL COMMON	311	4.90%	$ 59,227.10	$ 59,227.10
CAPE CANAVERAL COMMON	312	8.50%	$ 4,359.55	$ 4,359.55
CAPE CANAVERAL U1	312	8.80%	$ 484,171.51	$ 484,171.51
CAPE CANAVERAL U2	312	8.30%	$ 501,269.89	$ 501,269.89
MARTIN COMMON	312	4.60%	$ -	$ -
MARTIN COM FOSSIL	312	4.60%	$ 22,910.28	$ 4,850.00
MARTIN UNIT 1	311	3.30%	$ 32,980.15	$ 36,810.86
MARTIN UNIT 1	312	4.80%	$ 524,905.88	$ 521,075.17
MARTIN UNIT 2	311	3.30%	$ 33,155.90	$ 36,845.37
MARTIN UNIT 2	312	4.90%	$ 523,174.43	$ 519,484.96
MARTIN UNIT 3	343	5.70%	$ 390,420.29	$ 383,176.57
MARTIN UNIT 4	343	5.50%	$ 384,319.53	$ 377,207.01
RIVIERA COMMON	311	5.20%	$ 60,973.18	$ 60,973.18
RIVIERA COMMON	312	8.90%	$ 12,195.30	$ 4,689.16
RIVIERA UNIT 3	312	8.90%	$ 438,874.32	$ 438,874.32
RIVIERA UNIT 4	312	7.90%	$ 422,903.90	$ 422,903.90
FORT MYERS COMMON	312	3.40%	$ -	$ -
FORT MYERS UNIT 2	312	3.60%	$ -	$ -
FORT MYERS CT's	343	5.50%	$ -	$ -
MANATEE COMMON	312	4.60%	$ 13,378.02	$ 13,378.02
MANATEE UNIT 1	311	2.90%	$ 56,430.25	$ 56,430.25
MANATEE UNIT 1	312	4.00%	$ 473,304.93	$ 473,304.93
MANATEE UNIT 2	311	3.00%	$ 42,150.77	$ 56,332.75
MANATEE UNIT 2	312	4.20%	$ 523,586.18	$ 509,404.20
FT LAUDERDALE COMMON	341	5.30%	$ 58,859.79	$ 58,859.79
FT LAUDERDALE U4	343	6.50%	$ 446,205.27	$ 440,440.80
FT LAUDERDALE U5	343	6.60%	$ 451,322.61	$ 448,440.37
PT EVERGLADES COMMON	311	5.80%	$ 127,911.34	$ 127,911.34
PT EVERGLADES COMMON	312	7.70%	$ 14,092.44	$ 8,624.33
PT EVERGLADES UT1	312	6.10%	$ 479,325.32	$ 453,408.32
PT EVERGLADES UT2	312	6.50%	$ 500,777.48	$ 474,860.48
PT EVERGLADES UT3	312	7.80%	$ 503,843.57	$ 503,843.57
PT EVERGLADES UT4	312	8.40%	$ 512,009.55	$ 512,009.55
CUTLER COMMON	311	5.20%	$ 64,883.87	$ 64,883.87
CUTLER COMMON	312	8.80%	$ 11,663.14	$ 4,689.16
CUTLER UNIT 5	312	5.00%	$ 302,030.62	$ 302,030.62
CUTLER UNIT 6	312	5.10%	$ 314,098.14	$ 314,098.14
TURKEY UNIT 1	312	8.80%	$ 551,367.62	$ 551,367.62
TURKEY UNIT 2	312	6.70%	$ 505,398.92	$ 505,398.92
TURKEY COMMON	311	4.30%	$ 58,791.34	$ 59,056.19
TURKEY COMMON	312	6.90%	$ 19,027.83	$ 4,689.20
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	$ 106,814.52
SJRPP UNIT 2	312	4.20%	$ 106,783.43	$ 106,783.43
SCHERER UNIT 4	312	4.50%	$ 537,039.34	$ 537,039.34
POWER RESCOU-JUNO	391	3 yr amort	$ 10,284.15	$ 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
TOTAL FOR PROJECT 3			**$ 13,011,427.62**	**$ 12,557,642.49**

PROJECT NO. 5b

FOR 2002

PLANT NAME	PLANT ACCOUNT	DEPRECIATION RATE	APRIL PLANT IN SERVICE (EOM)	DECEMBER PLANT IN SERVICE (EOM)
PUTNAM COMMON	342	4.00%	$ 749,025.94	$ 749,025.94
SANFORD COMMON	311	2.80%	$ 796,754.11	$ 796,754.11
SANFORD COMMON RL	311	0.01%	$ 172,200.11	$ -
SANFORD UNIT 4 RL	312	0.00%	$ 65,105.42	$ -
CAPE CANAVERAL COMMON	311	4.90%	$ 268,748.69	$ 268,748.69
CAPE CANAVERAL FT	311	4.90%	$ 632,888.19	$ 632,888.19
MARTIN COM PPBT	311	3.60%	$ 638,132.62	$ 638,132.62
MARTIN COM FOSSIL	311	3.60%	$ 407,224.94	$ 407,224.94
MARTIN COM FOP	311	3.60%	$ 65,092.76	$ 65,092.76
MARTIN UNIT 1	311	3.30%	$ 176,338.83	$ 176,338.83
RIVIERA COMMON	311	5.20%	$ 727,734.38	$ 727,734.38
FORT MYERS COMMON	311	3.10%	$ -	$ -
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
MANATEE COMMON	311	3.50%	$ 169,197.84	$ 30,323.73
MANATEE COMMON	312	4.60%	$ 35,669.12	$ 174,543.23
PORT MANATEE TERM	311	3.50%	$ 3,006,557.60	$ 3,006,557.60
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
FT LAUDERDALE COMMON	342	4.30%	$ 898,110.65	$ 898,110.65
FT LAUDERDALE GTS	342	0.70%	$ 584,290.23	$ 584,290.23
PT EVERGLADES COMMON	311	5.80%	$ 347,607.15	$ -
PT EVERGLADES FOT	311	5.80%	$ 784,471.07	$ 1,132,078.22
PT EVERGLADES GTU	342	1.40%	$ 1,587,927.58	$ 1,587,927.58
TURKEY COMMON	311	4.30%	$ 39,972.13	$ -
TURKEY UNIT 2	311	5.20%	$ 42,158.96	$ 42,158.96
TURKEY COMMON	311	4.30%	$ 47,588.10	$ 87,560.23
SJRPP COMMON	311	3.40%	$ 42,091.24	$ 42,091.24
TOTAL FOR PROJECT 5			**$ 12,660,437.87**	**$ 12,423,132.34**

APPENDIX I

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

JANUARY 2003 – DECEMBER 2003 ESTIMATED/ACTUAL TRUE-UP

KMD-2
DOCKET NO. 030007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT _____
PAGES 1-43

Form 42-1E

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

Line No.		
1	Over/(Under) Recovery for the Current Period (Form 42-2E, Page 2 of 2, Line 5)	$879,032
2	Interest Provision (Form 42-2E, Page 2 of 2, Line 6)	($28,099)
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 2004	$850,933

( ) Reflects Underrecovery

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual 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 42-5E, Line 9)	137,881	150,468	179,769	180,280	151,390	265,177
	b - Capital Investment Projects (Form 42-7E, Line 9)	462,441	460,803	459,134	462,009	457,788	454,453
	c - Total Jurisdictional ECRC Costs	600,322	611,271	638,903	642,289	609,178	719,630
5	Over/(Under) Recovery (Line 3 - Line 4c)	30,744	139,383	119,386	96,926	241,532	324,916
6	Interest Provision (Form 42-3E, Line 10)	(7,198)	(6,367)	(5,402)	(4,569)	(3,856)	(2,735)
7	*Est/Act True-Up for 2002*	(7,271,601)	(6,642,088)	(5,903,106)	(5,183,155)	(4,484,831)	(3,641,188)
	a - Deferred True-Up from 2001 (Form 42-1A, Line 9)	205,347	205,347	205,347	205,347	205,347	205,347
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)*	(6,436,741)	(5,697,759)	(4,977,808)	(4,279,484)	(3,435,841)	(2,507,694)
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	($6,436,741)	($5,697,759)	($4,977,808)	($4,279,484)	($3,435,841)	($2,507,694)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual 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)	$1,670,760	$1,785,389	$1,760,673	$1,630,847	$1,483,541	$1,368,524	$18,110,016
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)	1,064,793	1,179,423	1,154,706	1,024,880	877,575	762,558	10,838,415
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5E, Line 9)	161,855	161,552	369,169	99,612	106,593	2,357,014	4,320,760
	b - Capital Investment Projects (Form 42-7E, Line 9)	454,413	455,114	456,465	486,232	514,732	515,039	5,638,623
	c - Total Jurisdictional ECRC Costs	616,268	616,666	825,634	585,844	621,325	2,872,053	9,959,383
5	Over/(Under) Recovery (Line 3 - Line 4c)	448,525	562,757	329,072	439,036	256,250	(2,109,495)	879,032
6	Interest Provision (Form 42-3E, Line 10)	(1,650)	(725)	151	976	1,771	1,505	(28,099)
7	Est/Act True-Up for 2002	(2,713,041)	(1,660,199)	(492,201)	442,989	1,488,968	2,352,955	(7,271,601)
	a - Deferred True-Up from 2001 (Form 42-1A, Line 9)	205,347	205,347	205,347	205,347	205,347	205,347	205,347
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)	(1,454,852)	(286,854)	648,336	1,694,315	2,558,302	1,056,280	1,056,280
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	($1,454,852)	($286,854)	$648,336	$1,694,315	$2,558,302	$1,056,280	$1,056,280

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual 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)	($7,066,254)	($6,436,741)	($5,697,759)	($4,977,808)	($4,279,484)	($3,435,841)
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	(6,429,543)	(5,691,392)	(4,972,406)	(4,274,915)	(3,431,985)	(2,504,959)
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	($13,495,797)	($12,128,133)	($10,670,165)	($9,252,723)	($7,711,469)	($5,940,800)
4	Average True-Up Amount (Line 3 x 1/2)	($6,747,899)	($6,064,067)	($5,335,083)	($4,626,362)	($3,855,735)	($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)	($6,367)	($5,402)	($4,569)	($3,856)	($2,735)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual 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)	($2,507,694)	($1,454,852)	($286,854)	$648,336	$1,694,315	$2,558,302	($31,242,334)
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	(1,453,202)	(286,129)	648,185	1,693,339	2,556,531	1,054,773	(23,091,703)
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	($3,960,896)	($1,740,981)	$361,331	$2,341,675	$4,250,846	$3,613,075	($54,334,037)
4	Average True-Up Amount (Line 3 x 1/2)	($1,980,448)	($870,491)	$180,666	$1,170,838	$2,125,423	$1,806,538	($27,167,019)
5	Interest Rate (First Day of Reporting Month)	1.00000%	1.00000%	1.00000%	1.00000%	1.00000%	1.00000%	N/A
6	Interest Rate (First Day of Subsequent Month)	1.00000%	1.00000%	1.00000%	1.00000%	1.00000%	1.00000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	2.00000%	2.00000%	2.00000%	2.00000%	2.00000%	2.00000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	1.00000%	1.00000%	1.00000%	1.00000%	1.00000%	1.00000%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.08333%	0.08333%	0.08333%	0.08333%	0.08333%	0.08333%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	($1,650)	($725)	$151	$976	$1,771	$1,505	($28,099)

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

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	$1,971,032	$2,208,755	($237,723)	-10.8%
3a	Continuous Emission Monitoring Systems-O&M	$636,975	$643,524	($6,549)	-1.0%
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	$306,177	$179,000	$127,177	71.0%
8a	Oil Spill Cleanup/Response Equipment-O&M	$168,888	$150,000	$18,888	12.6%
13	RCRA Corrective Action-O&M	$52,498	$50,000	$2,498	5.0%
14	NPDES Permit Fees-O&M	$123,543	$112,900	$10,643	9.4%
17a	Disposal of Noncontainerized Liquid Waste-O&M	$229,138	$269,000	($39,862)	-14.8%
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	$1,000,300	$1,000,300	$0	0.0%
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	$677,900	$677,900	$0	0.0%
19c	Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	($560,232)	($560,232)	$0	0.0%
20	Wastewater Discharge Elimination & Reuse	$32,611	$85,000	($52,389)	-61.6%
NA	Amortization of Gains on Sales of Emissions Allowances	($430,354)	($518,268)	$87,914	-17.0%
22	Pipeline Integrity Management	$72,784	$200,000	($127,216)	-63.6%
23	SPCC-Spill Prevention, Control & Countermeasures	$76,261	$175,000	($98,739)	-56.4%
2	Total O&M Activities	$4,357,521	$4,672,879	($315,358)	-6.7%
3	Recoverable Costs Allocated to Energy	$2,606,278	$2,783,610	($177,332)	-6.4%
4a	Recoverable Costs Allocated to CP Demand	$1,031,059	$1,169,085	($138,026)	-11.8%
4b	Recoverable Costs Allocated to GCP Demand	$720,184	$720,184	$0	0.0%

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-02-1735-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 2003 - December 2003

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	$6,083	($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
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
NA	Amortization of Gains on Sales of Emissions 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	SPCC - Spill Prevention, Control & Countermeasures	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 (Lines 7 + 8)	$ 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 add due to rounding.

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

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	$0	$0	$0	$0	$0	$2,061,980	$2,061,980	$1,971,032			$1,971,032
3a Continuous Emission Monitoring Systems-O&M	0	0	201,758	0	0	201,758	403,516	636,975			636,975
5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	42,402	42,402	42,402	42,402	42,402	42,402	254,412	306,177	306,177		
8a Oil Spill Cleanup/Response Equipment-O&M	21,333	21,333	21,333	21,333	21,333	21,333	127,998	168,888			168,888
13 RCRA Corrective Action-O&M	0	0	0	0	0	50,000	50,000	52,498	52,498		
14 NPDES Permit Fees-O&M	0	0	0	0	0	0	0	123,543	123,543		
17a Disposal of Noncontainerized Liquid Waste-O&M	16,500	16,500	16,500	16,500	16,500	16,500	99,000	229,138			229,138
19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	86,203	85,900	85,900	20,000	25,000	22,548	325,551	1,000,300		1,000,300	
19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	78,950	78,950	78,950	78,950	78,950	47,338	442,088	677,900	625,754		52,146
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	32,611	32,611		
NA Amortization of Gains on Sales of Emissions Allowances	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(215,178)	(430,354)			(430,354)
22 Pipeline Integrity Management	0	0	0	0	0	0	0	72,784	72,784		
23 SPCC - Spill Prevention, Control & Countermeasures	0	0	8,000	0	0	0	8,000	76,261	76,261		
2 Total of O&M Activities	$ 162,839	$ 162,536	$ 372,294	$ 100,636	$ 107,636	$ 2,381,310	$ 3,287,251	$ 4,357,521	$ 1,031,059	$ 720,184	$ 2,606,278
3 Recoverable Costs Allocated to Energy	$ 6,247	$ 6,247	$ 208,005	$ 6,247	$ 6,247	$ 2,267,554	$ 2,500,549	$ 2,606,278			
4a *Recoverable Costs Allocated to CP Demand*	$ 93,732	$ 93,732	$ 101,732	$ 97,732	$ 99,732	$ 114,551	$ 601,209	$ 1,031,059			
4b Recoverable Costs Allocated to GCP Demand	$ 62,860	$ 62,557	$ 62,557	$ (3,343)	$ 1,657	$ (795)	$ 185,493	$ 720,184			
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)	$ 6,184	$ 6,184	$ 205,880	$ 6,184	$ 6,184	$ 2,244,383	$ 2,474,999	$ 2,579,646			
8a Jurisdictional CP Demand Recoverable Costs (B)	$ 92,811	$ 92,811	$ 100,732	$ 96,771	$ 98,752	$ 113,426	$ 595,303	$ 1,020,930			
8b Jurisdictional GCP Demand Recoverable Costs (C)	$ 62,860	$ 62,557	$ 62,557	$ (3,343)	$ 1,657	$ (795)	$ 185,493	$ 720,184			
9 Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 161,855	$ 161,552	$ 369,169	$ 99,612	$ 106,593	$ 2,357,014	$ 3,255,795	$ 4,320,760			

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 2003 - December 2003

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	$ 2,072,617	$ 2,072,617	$ -	0.0%
3b	Continuous Emission Monitoring Systems-Capital	1,492,921	1,523,756	(30,835)	-2.0%
4b	Clean Closure Equivalency-Capital	6,132	6,132	0	0.0%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	1,506,397	1,633,262	(126,865)	-7.8%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	3,391	3,391	0	0.0%
8b	Oil Spill Cleanup/Response Equipment-Capital	135,506	167,578	(32,072)	-19.1%
10	Relocate Storm Water Runoff-Capital	11,898	11,898	0	0.0%
NA	SO2 Allowances-Negative Return on Investment	(145,847)	(139,813)	(6,034)	4.3%
12	Scherer Discharge Pipeline-Capital	90,844	90,844	0	0.0%
17b	Disposal of Noncontainerized Liquid Wate-Capital	50,581	50,581	0	0.0%
20	Wastewater Discharge Elimination & Reuse	214,086	205,243	8,843	4.3%
21	St. Lucie Turtle Net	86,640	69,713	16,927	24.3%
22	Pipeline Integrity Management	11,062	66,014	(54,952)	-83.2%
23	SPCC-Spill Prevention, Control & Countermeasures	159,772	241,438	(81,666)	-33.8%
2	Total Investment Projects-Recoverable Costs	$ 5,696,000	$ 6,002,654	$ (306,654)	-5.1%
3	Recoverable Costs Allocated to Energy	$ 3,594,793	$ 3,652,414	$ (57,621)	-1.6%
4	Recoverable Costs Allocated to Demand	$ 2,101,207	$ 2,350,240	$ (249,033)	-10.6%

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-02-1735-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 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
17b	Disposal of Noncontainerized Liquid Waste-Capital	4,382	4,352	4,321	4,291	4,261	4,230	25,837
20	Wastewater Discharge Elimination &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	0
23	SPCC - Spill Prevention, Control & Countermeasures	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 (Lines 7 + 8)	$ 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 42-4P, 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 2003 - December 2003

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	$ 172,272	$ 171,380	$ 170,488	$ 169,597	$ 168,705	$ 167,813	$ 1,020,255	$ 2,072,617		$ 2,072,617
3b	Continuous Emission Monitoring Systems-Capital	123,221	122,409	122,773	124,609	125,548	125,008	743,568	$ 1,492,921		1,492,921
4b	Clean Closure Equivalency-Capital	510	508	506	504	502	500	3,030	$ 6,132	5,660	472
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	124,036	123,743	123,449	126,105	128,754	128,446	754,533	$ 1,506,397	1,390,520	115,877
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	282	281	280	278	277	276	1,674	$ 3,391	3,130	261
8b	Oil Spill Cleanup/Response Equipment-Capital	11,199	11,130	11,061	11,403	11,435	11,363	67,591	$ 135,506	125,082	10,424
10	Relocate Storm Water Runoff-Capital	990	988	985	983	980	978	5,904	$ 11,898	10,983	915
NA	SO2 Allowances-Negative Return on Investment	(13,378)	(13,093)	(12,808)	(12,522)	(12,237)	(11,952)	(75,990)	$ (145,847)		(145,847)
12	Scherer Discharge Pipeline-Capital	7,558	7,534	7,510	7,486	7,462	7,438	44,988	$ 90,844	83,856	6,988
17b	Disposal of Noncontainerized Liquid Waste-Capital	4,200	4,170	4,139	4,109	4,078	4,048	24,744	$ 50,581	46,690	3,891
20	Wastewater Discharge Elimination &Reuse	17,077	17,023	16,969	18,688	20,402	20,339	110,498	$ 214,086	197,618	16,468
21	St. Lucie Turtle Net	7,228	7,210	7,193	7,175	7,158	7,140	43,104	$ 86,640	79,975	6,665
22	Pipeline Integrity Management	0	0	0	2,216	4,428	4,418	11,062	$ 11,062	10,211	851
23	SPCC - Spill Prevention, Control & Countermeasures	3,844	6,464	8,566	30,544	52,466	54,454	156,338	$ 159,772	147,482	12,290
2	Total Investment Projects - Recoverable Costs	$ 459,039	$ 459,747	$ 461,111	$ 491,175	$ 519,958	$ 520,269	$ 2,911,299	$ 5,696,000	$ 2,101,207	$ 3,594,793
3	Recoverable Costs Allocated to Energy	$ 295,725	$ 294,469	$ 294,350	$ 297,799	$ 300,319	$ 299,284	$ 1,781,946	$ 3,594,793		
4	Recoverable Costs Allocated to Demand	$ 163,314	$ 165,278	$ 166,761	$ 193,376	$ 219,639	$ 220,985	$ 1,129,353	$ 2,101,207		
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)	$ 292,703	$ 291,460	$ 291,342	$ 294,756	$ 297,251	$ 296,226	$ 1,763,738	$ 3,558,061		
8	Jurisdictional Demand Recoverable Costs (C)	$ 161,710	$ 163,654	$ 165,123	$ 191,476	$ 217,481	$ 218,813	$ 1,118,257	$ 2,080,562		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 454,413	$ 455,114	$ 456,465	$ 486,232	$ 514,732	$ 515,039	$ 2,881,995	$ 5,638,623		

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 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	9,879,603	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 42-8E, pages 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 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)	9,991,695	10,103,787	10,215,879	10,327,971	10,440,063	10,552,154	10,664,246	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	$7,507,681	$7,395,589	$7,283,497	$7,171,405	$7,059,314	$6,947,222	n/a
6.	Average Net Investment		7,563,727	7,451,635	7,339,543	7,227,451	7,115,360	7,003,268	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		44,827	44,163	43,499	42,834	42,170	41,506	541,913
	b. Debt Component (Line 6 x 2.4358% x 1/12)		15,353	15,126	14,898	14,671	14,443	14,215	185,602
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)		$172,272	$171,380	$170,488	$169,597	$168,705	$167,813	$2,072,617

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 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 2003.
(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 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 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 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	$145,001	$240,000	$0	$0	$476,845
	c. Retirements			$10,284					$45,319
	d. Other (A)								$159
2.	Plant-In-Service/Depreciation Base (B)	$12,614,452	12,614,452	12,604,168	12,749,169	12,989,169	12,989,169	12,989,169	n/a
3.	Less: Accumulated Depreciation (C)	5,165,178	5,231,680	5,287,614	5,354,148	5,421,518	5,489,411	5,557,303	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	$7,382,772	$7,316,554	$7,395,021	$7,567,651	$7,499,758	$7,431,866	n/a
6.	Average Net Investment		7,416,023	7,349,663	7,355,788	7,481,336	7,533,704	7,465,812	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		43,952	43,559	43,595	44,339	44,649	44,247	534,363
	b. Debt Component (Line 6 x 2.4358% x 1/12)		15,053	14,919	14,931	15,186	15,292	15,154	183,017
8.	Investment Expenses								
	a. Depreciation (E)		66,502	66,218	66,533	67,371	67,893	67,893	802,974
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)		(2,286)	(2,286)	(2,286)	(2,286)	(2,286)	(2,286)	(27,432)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$123,221	$122,409	$122,773	$124,609	$125,548	$125,008	$1,492,921

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 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 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 42-8E, pages 29-31.
(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 4.3665% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 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)	25,348	25,592	25,836	26,081	26,325	26,569	26,814	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$33,518	$33,274	$33,030	$32,785	$32,541	$32,297	$32,052	n/a
6.	Average Net Investment		33,396	33,152	32,907	32,663	32,419	32,174	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		198	196	195	194	192	191	2,384
	b. Debt Component (Line 6 x 2.4358% x 1/12)		68	67	67	66	66	65	816
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)		$510	$508	$506	$504	$502	$500	$6,132

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 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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	22,318	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 42-8E, pages 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 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	$508,290	$0	$0	$508,290
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$12,423,132	12,423,132	12,423,132	12,423,132	12,931,422	12,931,422	12,931,422	n/a
3.	Less: Accumulated Depreciation (C)	1,446,671	1,483,520	1,520,369	1,557,218	1,594,997	1,633,708	1,672,418	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	$10,939,612	$10,902,763	$10,865,914	$11,336,425	$11,297,714	$11,259,004	n/a
6.	Average Net Investment		10,958,036	10,921,187	10,884,339	11,101,169	11,317,069	11,278,359	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		64,944	64,726	64,507	65,792	67,072	66,842	788,157
	b. Debt Component (Line 6 x 2.4358% x 1/12)		22,243	22,168	22,093	22,534	22,972	22,893	269,940
8.	Investment Expenses								
	a. Depreciation (E)		36,849	36,849	36,849	37,780	38,710	38,710	448,300
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$124,036	$123,743	$123,449	$126,105	$128,754	$128,446	$1,506,397

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 42-8E, pages 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 42-8E, pages 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 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)	14,680	14,832	14,985	15,138	15,290	15,443	15,595	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$16,350	$16,198	$16,045	$15,892	$15,740	$15,587	$15,435	n/a
6.	Average Net Investment		16,274	16,121	15,969	15,816	15,664	15,511	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		96	96	95	94	93	92	1,163
	b. Debt Component (Line 6 x 2.4358% x 1/12)		33	33	32	32	32	31	398
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)		$282	$281	$280	$278	$277	$276	$3,391

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 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 42-8E, pages 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 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	$25,954	$0	$0	$38,579
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$738,711	738,711	738,711	738,711	764,665	764,665	764,665	n/a
3.	Less: Accumulated Depreciation (C)	417,284	425,960	434,636	443,313	452,298	461,283	470,269	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$321,428	$312,751	$304,075	$295,399	$312,367	$303,382	$294,397	n/a
6.	Average Net Investment		317,089	308,413	299,737	303,883	307,875	298,889	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,879	1,828	1,776	1,801	1,825	1,771	22,994
	b. Debt Component (Line 6 x 2.4358% x 1/12)		644	626	608	617	625	607	7,875
8.	Investment Expenses								
	a. Depreciation (E)		8,676	8,676	8,676	8,985	8,985	8,985	104,639
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,199	$11,130	$11,061	$11,403	$11,435	$11,363	$135,506

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 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 42-8E, pages 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 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)	32,651	32,966	33,280	33,594	33,908	34,222	34,536	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$85,143	$84,828	$84,514	$84,200	$83,886	$83,572	$83,258	n/a
6.	Average Net Investment		84,985	84,671	84,357	84,043	83,729	83,415	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		504	502	500	498	496	494	6,055
	b. Debt Component (Line 6 x 2.4358% x 1/12)		173	172	171	171	170	169	2,074
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)		$990	$988	$985	$983	$980	$978	$11,898

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 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 42-8E, pages 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 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)	293,481	296,510	299,539	302,568	305,597	308,626	311,655	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$570,779	$567,750	$564,721	$561,692	$558,663	$555,634	$552,605	n/a
6.	*Average Net Investment*		569,264	566,235	563,207	560,178	557,149	554,120	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,374	3,356	3,338	3,320	3,302	3,284	40,593
	b. Debt Component (Line 6 x 2.4358% x 1/12)		1,156	1,149	1,143	1,137	1,131	1,125	13,903
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)		$7,558	$7,534	$7,510	$7,486	$7,462	$7,438	$90,844

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 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 42-8E, pages 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 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)	$311,009	311,009	311,009	311,009	311,009	311,009	311,009	n/a
3.	Less: Accumulated Depreciation (C)	261,349	265,169	268,989	272,809	276,629	280,449	284,269	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$49,660	$45,840	$42,020	$38,200	$34,380	$30,560	$26,740	n/a
6.	Average Net Investment		47,750	43,930	40,110	36,290	32,470	28,650	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		283	260	238	215	192	170	3,532
	b. Debt Component (Line 6 x 2.4358% x 1/12)		97	89	81	74	66	58	1,210
8.	Investment Expenses								
	a. Depreciation (E)		3,820	3,820	3,820	3,820	3,820	3,820	45,840
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,200	$4,170	$4,139	$4,109	$4,078	$4,048	$50,581

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 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 42-8E, pages 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 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	$300,583	$0	$0	$300,583
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$1,563,995	1,563,995	1,563,995	1,563,995	1,864,578	1,864,578	1,864,578	n/a
3.	Less: Accumulated Depreciation (C)	$262,593	269,342	276,091	282,841	290,168	298,075	305,981	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	$1,294,653	$1,287,903	$1,281,154	$1,574,410	$1,566,503	$1,558,597	n/a
6.	Average Net Investment		1,298,027	1,291,278	1,284,529	1,427,782	1,570,456	1,562,550	
7.	Return on Average Net Investment								
	Equity Component grossed up for taxes (D)		7,693	7,653	7,613	8,462	9,307	9,261	96,986
	Debt Component (Line 6 x 2.4358% x 1/12)		2,635	2,621	2,607	2,898	3,188	3,172	33,217
8.	Investment Expenses								
	a. Depreciation (E)		6,749	6,749	6,749	7,328	7,906	7,906	83,882
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$17,077	$17,023	$16,969	$18,688	$20,402	$20,339	$214,086

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 42-8E, pages 29-31.

(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 29-31.

(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.

(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	$822,061	$821,148	$818,938	$816,728	$814,518	n/a
6.	Average Net Investment		809,698	823,164	821,604	820,043	817,833	815,623	
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 42-8E, pages 29-31.

(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 29-31.

(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.

(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 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	$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	16,482	18,692	20,902	23,112	25,322	27,532	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$814,518	$812,308	$810,098	$807,888	$805,678	$803,468	$801,258	n/a
6.	Average Net Investment		813,413	811,203	808,993	806,783	804,573	802,363	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		4,821	4,808	4,795	4,781	4,768	4,755	57,816
	b. Debt Component (Line 6 x 2.4358% x 1/12)		1,651	1,647	1,642	1,638	1,633	1,629	19,802
8.	Investment Expenses								
	a. Depreciation (E)		2,210	2,210	2,210	2,210	2,210	2,210	26,470
	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)		$7,228	$7,210	$7,193	$7,175	$7,158	$7,140	$86,640

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 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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: 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 2.4358% 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 42-8E, pages 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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: 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	$405,000	$0	$0	$405,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	405,000	405,000	405,000	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	608	1,823	3,038	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	$404,393	$403,178	$401,963	n/a
6.	Average Net Investment		0	0	0	202,196	403,785	402,570	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	1,198	2,393	2,386	5,977
	b. Debt Component (Line 6 x 2.4358% x 1/12)		0	0	0	410	820	817	2,047
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	608	1,215	1,215	3,038
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$2,216	$4,428	$4,418	$11,062

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 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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: 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 42-8E, pages 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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 Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$315,900	$215,900	$215,900	$3,566,150	$215,900	$215,900	$4,978,601
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$232,951	548,851	764,751	980,651	4,546,801	4,762,701	4,978,601	n/a
3.	Less: Accumulated Depreciation (C)	$644	1,386	2,640	4,290	12,913	28,508	44,500	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$232,307	$547,466	$762,111	$976,361	$4,533,889	$4,734,193	$4,934,101	n/a
6.	Average Net Investment		389,886	654,789	869,236	2,755,125	4,634,041	4,834,147	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,311	3,881	5,152	16,329	27,464	28,650	85,864
	b. Debt Component (Line 6 x 2.4358% x 1/12)		791	1,329	1,764	5,592	9,406	9,813	29,408
8.	Investment Expenses								
	a. Depreciation (E)		742	1,254	1,650	8,623	15,596	15,992	44,500
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,844	$6,464	$8,566	$30,544	$52,466	$54,454	$159,772

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 29-31.
(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 29-31.
(F) Applicable amortization period(s). See Form 42-8E, pages 29-31.
(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		(1,467,138)	(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		($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)		($11,342)	($11,342)	($11,342)	($11,342)	($11,342)	($158,466)	($215,175)	(E)
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 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 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 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	(1,699,384)	(1,663,522)	(1,627,659)	(1,591,797)	(1,555,934)	(1,520,072)	(1,484,209)		
2	Total Working Capital	($1,699,384)	($1,663,522)	($1,627,659)	($1,591,797)	($1,555,934)	($1,520,072)	($1,484,209)		
3	Average Net Working Capital Balance		(1,681,453)	(1,645,590)	(1,609,728)	(1,573,865)	(1,538,003)	(1,502,140)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(9,965)	(9,753)	(9,540)	(9,328)	(9,115)	(8,903)	(108,639)	
	b Debt Component (Line 6 x 2.358% x 1/12)		(3,413)	(3,340)	(3,267)	(3,195)	(3,122)	(3,049)	(37,208)	
5	Total Return Component		($13,378)	($13,093)	($12,808)	($12,522)	($12,237)	($11,952)	($145,848)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(430,350)	
	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)		($35,863)	($35,863)	($35,863)	($35,863)	($35,863)	($35,863)	($430,350)	(E)
8	*Total System Recoverable Expenses* (Lines 5+7)		($49,241)	($48,956)	($48,670)	($48,385)	($48,100)	($47,814)		
	a Recoverable Costs Allocated to Energy		(49,241)	(48,956)	(48,670)	(48,385)	(48,100)	(47,814)		
	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)		(48,521)	(48,240)	(47,958)	(47,677)	(47,396)	(47,115)	(567,771)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($48,521)	($48,240)	($47,958)	($47,677)	($47,396)	($47,115)	($567,771)	

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

FOR 2003

Project No.	PLANT NAME	PLANT ACCOUNT	DEPRECIATION RATE/ AMORTIZATION PERIOD	ACTUAL JANUARY PLANT IN SERVICE (BOM)	ESTIMATED/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	$ 657,953.94
	MARTIN COM PPBT	316	5yr	$ 15,228.31	$ 15,228.31
	MARTIN COM PPBT	316	7yr	$ 53,549.84	$ 53,549.84
	CAPE CANAVERAL FT	316	7yr	$ -	$ 4,362.96
	SANFORD	316	7yr	$ 5,094.50	$ 5,094.50
	TURKEY COMMON	316	7yr	$ 5,368.46	$ 5,368.46
	TOTAL FOR PROJECT 8			**726,085.67**	**764,665.33**
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	$831,500.94
	RIVIERA COMMON	311	5.20%	$560,786.81	$560,786.81
	PT EVERGLADES COMMON	311	5.80%	$296,707.34	$362,290.34
	MARTIN COMMON	311	3.60%	$0.00	$110,000.00
	TOTAL FOR PROJECT 20			**$1,563,995.09**	**$1,864,578.09**
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)	ESTIMATED/ACTUAL DECEMBER PLANT IN SERVICE (EOM)
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	$ 346,065.01
PUTNAM UNIT 2	343	6.30%	$ 342,873.31	$ 358,915.31
SANFORD COMMON	312	3.50%	$ -	$ 5,168.21
SANFORD UNIT 3	311	2.40%	$ 54,282.08	$ 54,282.08
SANFORD UNIT 3	312	2.40%	$ 76,028.32	$ 158,107.02
SANFORD UNIT 3 RL	312	0.00%	$ 447,259.15	$ 442,603.11
SANFORD UNIT 4 RL	312	0.00%	$ 41,859.48	$ 41,859.48
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	8.80%	$ 484,171.51	$ 502,857.87
CAPE CANAVERAL U2	312	8.30%	$ 501,269.89	$ 519,956.24
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	4.80%	$ 521,075.17	$ 553,158.17
MARTIN UNIT 2	311	3.30%	$ 36,845.37	$ 36,845.37
MARTIN UNIT 2	312	4.90%	$ 519,484.96	$ 551,568.96
MARTIN UNIT 3	343	5.70%	$ 383,176.57	$ 386,605.43
MARTIN UNIT 4	343	5.50%	$ 377,207.01	$ 380,685.87
RIVIERA COMMON	311	5.20%	$ 60,973.18	$ 60,973.18
RIVIERA COMMON	312	8.90%	$ 4,689.16	$ 8,166.97
RIVIERA UNIT 3	312	8.90%	$ 438,874.32	$ 446,895.32
RIVIERA UNIT 4	312	7.90%	$ 422,903.90	$ 430,924.90
FORT MYERS CT's	343	5.50%	$ -	$ 64,167.00
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	$ 481,325.93
MANATEE UNIT 2	311	3.00%	$ 56,332.75	$ 56,332.75
MANATEE UNIT 2	312	4.20%	$ 509,404.20	$ 517,425.20
FT LAUDERDALE COMMON	341	5.30%	$ 58,859.79	$ 58,859.79
FT LAUDERDALE U4	343	6.50%	$ 440,440.80	$ 458,222.61
FT LAUDERDALE U5	343	6.60%	$ 448,440.37	$ 466,221.29
PT EVERGLADES COMMON	311	5.80%	$ 127,911.34	$ 127,911.34
PT EVERGLADES COMMON	312	7.70%	$ 8,624.33	$ 19,111.95
PT EVERGLADES UT1	312	6.10%	$ 453,408.32	$ 469,449.32
PT EVERGLADES UT2	312	6.50%	$ 474,860.48	$ 490,902.48
PT EVERGLADES UT3	312	7.80%	$ 503,843.57	$ 503,843.57
PT EVERGLADES UT4	312	8.40%	$ 512,009.55	$ 512,009.55
CUTLER COMMON	311	5.20%	$ 64,883.87	$ 64,883.87
CUTLER COMMON	312	8.80%	$ 4,689.16	$ 6,408.88
CUTLER UNIT 5	312	5.00%	$ 302,030.62	$ 310,051.62
CUTLER UNIT 6	312	5.10%	$ 314,098.14	$ 322,119.14
TURKEY UNIT 1	312	8.80%	$ 551,367.62	$ 554,555.15
TURKEY UNIT 2	312	6.70%	$ 505,398.92	$ 513,659.44
TURKEY COMMON	311	4.30%	$ 59,056.19	$ 59,056.19
TURKEY COMMON	312	6.90%	$ 4,689.20	$ 8,168.05
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	$ 106,814.52
SJRPP UNIT 2	312	4.20%	$ 106,783.43	$ 106,783.43
SCHERER UNIT 4	312	4.50%	$ 537,039.34	$ 537,039.34
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
TOTAL FOR PROJECT 3			**$ 12,557,642.49**	**$ 12,989,168.27**

PROJECT NO. 5b

FOR 2003

PLANT NAME	PLANT ACCOUNT	DEPRECIATION RATE	ACTUAL JANUARY PLANT IN SERVICE (BOM)	ESTIMATED/ACTUAL DECEMBER PLANT IN SERVICE (EOM)
PUTNAM COMMON	342	4.00%	$ 749,025.94	$ 749,025.94
SANFORD COMMON	311	2.80%	$ 796,754.11	$ -
SANFORD UNIT 3	311	5.80%	$ -	$ 796,754.11
CAPE CANAVERAL COMMON	311	4.90%	$ 268,748.69	$ 268,748.69
CAPE CANAVERAL FT	311	4.90%	$ 632,888.19	$ 632,888.19
MARTIN COM PPBT	311	3.60%	$ 638,132.62	$ 638,132.62
MARTIN COM FOSSIL	311	3.60%	$ 407,224.94	$ 407,224.94
MARTIN COM FOP	311	3.60%	$ 65,092.76	$ 65,092.76
MARTIN UNIT 1	311	3.30%	$ 176,338.83	$ 176,338.83
RIVIERA COMMON	311	5.20%	$ 727,734.38	$ 727,734.38
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
MANATEE COMMON	311	3.50%	$ 30,323.73	$ 30,323.73
MANATEE COMMON	312	4.60%	$ 174,543.23	$ 174,543.23
PORT MANATEE TERM	311	3.50%	$ 3,006,557.60	$ 3,006,557.60
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
FT LAUDERDALE COMMON	342	4.30%	$ 898,110.65	$ 898,110.65
FT LAUDERDALE GTS	342	0.70%	$ 584,290.23	$ 584,290.23
PT EVERGLADES FOT	311	5.80%	$ 1,132,078.22	$ 1,478,078.22
PT EVERGLADES GTU	342	1.40%	$ 1,587,927.58	$ 1,750,217.58
TURKEY COMMON	311	4.30%	$ -	$ -
TURKEY UNIT 2	311	5.20%	$ 42,158.96	$ 42,158.96
SJRPP COMMON	311	3.40%	$ 42,091.24	$ 42,091.24
TOTAL FOR PROJECT 5			**$ 12,335,572.11**	**$ 12,843,862.11**
MARTIN TERMINAL	311	3.60%	$0.00	$ 405,000.00
TOTAL FOR PROJECT 22			**$0.00**	**$ 405,000.00**
PUTNAM COMMON	342	4.00%	$0.00	$ 636,125.00
SANFORD COMMON	342	4.50%	$0.00	$ 30,625.00
CAPE CANAVERAL COMMON	311	4.90%	$0.00	**$ 71,875.00**
RIVIERA COMMON	311	5.20%	$0.00	$ 66,875.00
FORT MYERS COMMON	342	4.50%	$0.00	$ 668,375.00
FT LAUDERDALE COMMON	342	4.30%	$0.00	**$ 965,125.00**
PT EVERGLADES COMMON	311	5.80%	$0.00	**$ 884,375.00**
TURKEY COMMON	311	4.30%	$0.00	$ 26,875.00
JUNO OFFICE	390	2.80%	$0.00	$ 50,000.00
GENERAL OFFICE	390	2.80%	$0.00	$ 50,000.00
POWER SUPPLY SUBSTATIONS	352/361	2.20%	$0.00	$ 1,528,351.00
TOTAL FOR PROJECT 23			**$0.00**	**$ 4,978,601.00**

APPENDIX I

ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1P THROUGH 42-7P

JANUARY 2004 – DECEMBER 2004
PROJECTIONS

KMD-3
DOCKET NO. 030007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT _____
PAGES 1-72

Florida Power & Light Company

Environmental Cost Recovery Clause

Total Jurisdictional Amount to Be Recovered

For the Projected Period

January 2004 to December 2004

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)	2,720,910	1,925,498	879,869	5,526,277
	b Projected Capital Projects (FORM 42-3P, Page 2 of 2, Lines 7 through 9)	4,895,758	3,376,516	0	8,272,274
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	7,616,668	5,302,014	879,869	13,798,551
2	True-up for Estimated Over/(Under) Recovery for the current period January 2003 - December 2003 (FORM 42-1E, Line 4, filed on August 8, 2003)	524,408	264,993	61,533	850,933
3	Final True-up Over/(Under) for the period January 2002 - December 2002 (FORM 42-1A, Line 7, filed on April 1, 2003)	140,497	49,062	15,790	205,349
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2004 - December 2004 (Line 1 - Line 2 - Line 3)	6,951,763	4,987,959	802,546	12,742,269
5a	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier 1.01597)	7,062,783	5,067,617	815,363	12,945,763

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 2004 - December 2004

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	$0	$0	$0	$0	$0	$0	$0
	3a Continuous Emission Monitoring Systems-O&M	0	0	158,160	0	0	158,160	316,320
	4a Clean Closure Equivalency-O&M	0	0	0	0	0	0	0
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	38,375	38,375	38,375	38,375	38,375	38,375	230,250
	5c Maintenance of Stationary Above Ground Fuel Storage Tanks-Spill Abatement	0	0	0	0	0	0	0
	8a Oil Spill Cleanup/Response Equipment-O&M	13,833	13,833	13,833	13,833	13,833	13,833	82,998
	8c Oil Spill Cleanup/Response Equipment-Revenue	0	0	0	0	0	0	0
	9 Low-Level Radioactive Waste Access Fees-O&M	0	0	0	0	0	0	0
	13 RCRA Corrective Action-O&M	4,167	4,167	4,167	4,167	4,167	4,167	25,002
	14 NPDES Permit Fees-O&M	134,205	0	0	0	0	0	134,205
	17a Disposal of Noncontainerized Liquid Waste-O&M	0	0	99,000	0	0	90,000	189,000
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	162,014	202,965	203,277	32,593	51,331	45,981	698,161
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	84,554	110,465	102,527	100,443	49,131	37,181	484,301
	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	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(215,178)
	22 Pipeline Integrity Management	3,334	3,334	3,334	3,334	3,334	3,334	20,004
	23 SPCC - Spill Prevention, Control & Countermeasures	10,000	10,000	15,000	15,000	15,000	65,000	130,000
	26 UST Replacement/Removal	2,500	10,000	25,000	10,000	6,000	8,000	61,500
	27 Lowest Quality Water Source	30,850	30,850	30,850	30,850	30,850	30,850	185,100
2	Total of O&M Activities	$ 401,283	$ 341,440	$ 610,974	$ 166,046	$ 129,472	$ 412,332	$ 2,061,547
3	Recoverable Costs Allocated to Energy	$ (17,321)	$ (15,328)	$ 241,221	$ (16,099)	$ (20,046)	$ 227,194	$ 399,620
4a	Recoverable Costs Allocated to CP Demand	$ 279,933	$ 177,146	$ 189,819	$ 172,895	$ 121,530	$ 162,500	$ 1,103,824
4b	Recoverable Costs Allocated to GCP Demand	$ 138,671	$ 179,622	$ 179,934	$ 9,250	$ 27,988	$ 22,638	$ 558,103
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)	$ (17,105)	$ (15,137)	$ 238,206	$ (15,898)	$ (19,796)	$ 224,355	$ 394,625
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 276,695	$ 175,097	$ 187,623	$ 170,895	$ 120,124	$ 160,619	$ 1,091,053
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 138,671	$ 179,622	$ 179,934	$ 9,250	$ 27,988	$ 22,638	$ 558,103
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 398,261	$ 339,582	$ 605,763	$ 164,247	$ 128,316	$ 407,612	$ 2,043,781

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 2004 - December 2004

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	GCP Demand	Energy
1	Description of O&M Activities											
	1 Air Operating Permit Fees-O&M	$0	$0	$0	$0	$0	$2,061,980	$2,061,980	$2,061,980			$2,061,980
	3a Continuous Emission Monitoring Systems-O&M	0	0	158,160	0	0	158,160	316,320	632,640			632,640
	4a Clean Closure Equivalency-O&M	0	0	0	0	0	0	0	0	0		0
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	38,375	38,375	38,375	38,375	38,375	38,375	230,250	460,500	460,500		
	5c Maintenance of Stationary Above Ground Fuel Storage Tanks-Spill Abatement	0	0	0	0	0	0	0	0	0		0
	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
	8c Oil Spill Cleanup/Response Equipment-Revenue	0	0	0	0	0	0	0	0	0		0
	9 Low-Level Radioactive Waste Access Fees-O&M	0	0	0	0	0	0	0	0	0		0
	13 RCRA Corrective Action-O&M	4,167	4,167	4,167	4,167	4,167	4,167	25,002	50,004	50,004		
	14 NPDES Permit Fees-O&M	0	0	0	0	0	0	0	134,205	134,205		
	17a Disposal of Noncontainerized Liquid Waste-O&M	0	0	49,500	16,500	0	33,000	99,000	288,000			288,000
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	39,881	39,881	39,881	125,769	129,112	87,300	461,824	1,159,985		1,159,985	
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	44,281	44,281	37,681	42,069	68,112	41,550	277,974	762,275	703,638		58,637
	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	25,000	25,000	50,000	50,000	50,000		
	NA Amortization of Gains on Sales of Emissions Allowances	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(215,178)	(430,356)			(430,356)
	22 *Pipeline Integrity Management*	3,334	3,334	3,334	3,334	3,334	3,334	20,004	40,008	40,008		
	23 SPCC - Spill Prevention, Control & Countermeasures	55,000	55,000	0	0	0	10,000	120,000	250,000	250,000		
	26 UST Replacement/Removal	29,550	15,000	5,000	19,000	5,000	13,000	86,550	148,050	148,050		
	27 Lowest Quality Water Source	30,850	30,850	30,850	30,850	30,850	30,850	185,100	370,200	370,200		
2	Total of O&M Activities	$ 176,722	$ 162,172	$ 298,232	$ 211,348	$ 235,234	$ 2,438,000	$ 3,521,708	$ 5,583,255	$ 1,948,036	$ 879,869	$ 2,755,350
3	Recoverable Costs Allocated to Energy	$ (20,419)	$ (20,419)	$ 186,733	$ (4,090)	$ (18,586)	$ 2,232,511	$ 2,355,729	$ 2,755,350			
4a	Recoverable Costs Allocated to CP Demand	$ 180,603	$ 166,053	$ 94,961	$ 113,012	$ 148,051	$ 141,532	$ 844,213	$ 1,948,036			
4b	Recoverable Costs Allocated to GCP Demand	$ 16,538	$ 16,538	$ 16,538	$ 102,426	$ 105,769	$ 63,957	$ 321,766	$ 879,869			
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)*	$ (20,164)	$ (20,164)	$ 184,399	$ (4,038)	$ (18,354)	$ 2,204,606	$ 2,326,285	$ 2,720,910			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 178,514	$ 164,132	$ 93,862	$ 111,704	$ 146,338	$ 139,895	$ 834,445	$ 1,925,498			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 16,538	$ 16,538	$ 16,538	$ 102,426	$ 105,769	$ 63,957	$ 321,766	$ 879,869			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 174,888	$ 160,506	$ 294,799	$ 210,092	$ 233,753	$ 2,408,458	$ 3,482,496	$ 5,526,277			

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 2004 - December 2004

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	$ 165,858	$ 164,984	$ 164,109	$ 163,234	$ 162,360	$ 161,485	$ 982,030
3b	Continuous Emission Monitoring Systems-Capital	123,864	123,871	123,338	123,257	123,175	122,640	740,145
4b	Clean Closure Equivalency-Capital	493	492	490	488	486	484	2,933
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	129,314	131,915	131,599	134,080	136,553	136,220	799,681
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	272	271	270	269	268	266	1,616
8b	Oil Spill Cleanup/Response Equipment-Capital	11,656	11,685	11,612	11,804	11,847	11,721	70,325
10	Relocate Storm Water Runoff-Capital	962	960	958	955	953	950	5,738
NA	SO2 Allowances-Negative Return on Investment	(11,440)	(11,160)	(10,881)	(10,601)	(10,321)	(10,821)	(65,224)
12	Scherer Discharge Pipeline-Capital	7,329	7,305	7,281	7,258	7,234	7,210	43,617
17b	Disposal of Noncontainerized Liquid Waste-Capital	4,014	3,984	3,954	3,924	3,894	3,865	23,635
20	Wastewater Discharge Elimination &Reuse	21,785	23,468	23,397	23,327	23,256	23,185	138,418
21	St. Lucie Turtle Net	6,999	6,982	6,965	6,947	6,930	6,913	41,736
22	Pipeline Integrity Management	6,531	8,702	8,683	8,664	8,645	8,627	49,852
23	*SPCC - Spill Prevention, Control & Countermeasures*	75,284	96,594	97,993	103,248	108,490	109,837	591,446
24	Manatee Rebum	5,156	7,886	10,617	15,025	19,434	19,434	77,552
25	Pt. Everglades ESP Technology	11,118	17,672	24,849	33,781	43,870	54,363	185,653
2	Total Investment Projects - Recoverable Costs	$ 559,195	$ 595,611	$ 605,234	$ 625,660	$ 647,074	$ 656,379	$ 3,689,153
3	Recoverable Costs Allocated to Energy	$ 314,913	$ 325,742	$ 334,586	$ 347,847	$ 362,253	$ 370,892	$ 2,056,233
4	Recoverable Costs Allocated to Demand	$ 244,282	$ 269,869	$ 270,648	$ 277,813	$ 284,821	$ 285,487	$ 1,632,920
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)	$ 310,977	$ 321,671	$ 330,404	$ 343,499	$ 357,725	$ 366,256	$ 2,030,532
8	Jurisdictional Demand Recoverable Costs (C)	$ 241,456	$ 266,747	$ 267,517	$ 274,599	$ 281,526	$ 282,184	$ 1,614,029
9	Total Jurisdictional Recoverable Costs for *Investment Projects (Lines 7 + 8)*	$ 552,433	$ 588,418	$ 597,921	$ 618,098	$ 639,251	$ 648,440	$ 3,644,561

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 2004 - December 2004

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	$ 160,611	$ 159,736	$ 158,862	$ 157,987	$ 157,112	$ 156,238	$ 950,546	$ 1,932,576		$ 1,932,576
	3b Continuous Emission Monitoring Systems-Capital	122,556	122,037	121,502	121,419	121,335	120,797	729,646	$ 1,469,791		1,469,791
	4b Clean Closure Equivalency-Capital	482	480	478	476	474	472	2,862	$ 5,795	5,349	446
	5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	136,603	136,984	136,647	137,026	137,404	137,063	821,727	$ 1,621,408	1,496,684	124,724
	7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	265	264	263	262	260	259	1,573	$ 3,189	2,944	245
	8b Oil Spill Cleanup/Response Equipment-Capital	11,911	11,900	11,825	12,013	12,001	11,924	71,574	$ 141,899	130,984	10,915
	10 Relocate Storm Water Runoff-Capital	948	945	943	940	938	936	5,650	$ 11,388	10,512	876
	NA SO2 Allowances-Negative Return on Investment	(11,322)	(11,042)	(10,762)	(10,482)	(10,203)	(9,923)	(63,734)	$ (128,958)		(128,958)
	12 Scherer Discharge Pipeline-Capital	7,187	7,163	7,140	7,116	7,092	7,069	42,767	$ 86,384	79,739	6,645
	17b Disposal of Noncontainerized Liquid Waste-Capital	3,835	0	0	0	0	0	3,835	$ 27,470	25,357	2,113
	20 Wastewater Discharge Elimination &Reuse	23,114	23,044	22,973	22,902	22,831	22,761	137,625	$ 276,043	254,809	21,234
	21 St. Lucie Turtle Net	6,896	6,878	6,861	6,844	6,827	6,809	41,115	$ 82,851	76,478	6,373
	22 Pipeline Integrity Management	8,608	8,589	8,570	8,551	8,532	8,513	51,363	$ 101,215	93,429	7,786
	23 SPCC - Spill Prevention, Control & Countermeasures	115,064	120,279	121,599	126,799	131,986	135,893	751,620	$ 1,343,066	1,239,753	103,313
	24 Manatee Rebum	19,434	19,434	30,396	43,542	45,727	70,577	229,110	$ 306,662		306,662
	25 Pt. Everglades ESP Technology	68,235	103,654	144,864	172,329	197,297	220,952	907,331	$ 1,092,984		1,092,984
2	Total Investment Projects - Recoverable Costs	$ 674,427	$ 710,345	$ 762,161	$ 807,724	$ 839,613	$ 890,340	$ 4,684,610	$ 8,373,763	$ 3,416,038	$ 4,957,725
3	Recoverable Costs Allocated to Energy	$ 383,738	$ 418,167	$ 469,270	$ 509,636	$ 536,525	$ 584,156	$ 2,901,492	$ 4,957,725		
4	Recoverable Costs Allocated to Demand	$ 290,689	$ 292,178	$ 292,891	$ 298,088	$ 303,088	$ 306,184	$ 1,783,118	$ 3,416,038		
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)	$ 378,942	$ 412,940	$ 463,404	$ 503,266	$ 529,819	$ 576,855	$ 2,865,226	$ 4,895,758		
8	Jurisdictional Demand Recoverable Costs (C)	$ 287,326	$ 288,797	$ 289,503	$ 294,639	$ 299,581	$ 302,641	$ 1,762,487	$ 3,376,516		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 666,268	$ 701,737	$ 752,907	$ 797,905	$ 829,400	$ 879,496	$ 4,627,713	$ 8,272,274		

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 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 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)	10,664,246	10,776,338	10,888,430	11,000,521	11,112,613	11,224,705	11,336,797	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$6,947,222	$6,835,130	$6,723,038	$6,610,947	$6,498,855	$6,386,763	$6,274,671	n/a
6.	Average Net Investment		6,891,176	6,779,084	6,666,992	6,554,901	6,442,809	6,330,717	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		40,841	40,177	39,513	38,848	38,184	37,520	235,083
	b. Debt Component (Line 6 x 2.2507% x 1/12)		12,925	12,715	12,504	12,294	12,084	11,874	74,396
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)		$165,858	$164,984	$164,109	$163,234	$162,360	$161,485	$982,030

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 4.3685% 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 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 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)	11,336,797	11,448,889	11,560,981	11,673,072	11,785,164	11,897,256	12,009,348	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$6,274,671	$6,162,579	$6,050,487	$5,938,396	$5,826,304	$5,714,212	$5,602,120	n/a
6.	Average Net Investment		6,218,625	6,106,533	5,994,442	5,882,350	5,770,258	5,658,166	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		36,855	36,191	35,527	34,862	34,198	33,534	446,250
	b. Debt Component (Line 6 x 2.2507% x 1/12)		11,664	11,453	11,243	11,033	10,823	10,612	141,224
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)		$160,611	$159,736	$158,862	$157,987	$157,112	$156,238	$1,932,576

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 4.3685% 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 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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$85,500	$0	$0	$69,500	$0	$0	$155,000
	c. Retirements					$0	$0	$0	$0
	d. Other (A)							$0	$0
2.	Plant-In-Service/Depreciation Base (B)	$12,989,169	13,074,669	13,074,669	13,074,669	13,144,169	13,144,169	13,144,169	0
3.	Less: Accumulated Depreciation (C)	5,557,303	5,625,401	5,693,703	5,762,006	5,830,490	5,899,157	5,967,824	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$7,431,866	$7,449,268	$7,380,966	$7,312,663	$7,313,679	$7,245,012	$7,176,345	n/a
6.	Average Net Investment		7,440,567	7,415,117	7,346,815	7,313,171	7,279,345	7,210,679	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		44,097	43,946	43,542	43,342	43,142	42,735	260,804
	b. Debt Component (Line 6 x 2.2507% x 1/12)		13,955	13,908	13,780	13,716	13,653	13,524	82,536
8.	Investment Expenses								
	a. Depreciation (E)		68,098	68,303	68,303	68,485	68,667	68,667	410,521
	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)		$123,864	$123,871	$123,338	$123,257	$123,175	$122,640	$740,145

Notes:

(A) Cost of removal in June 2003.
(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 4.3685% 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 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 Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$69,500	$0	$0	$69,500	$0	$0	$294,000
	c. Retirements			$38,827					$38,827
	d. Other (A)								$0
2.	Plant-In-Service/Depreciation Base (B)	$13,144,169	13,213,669	13,174,842	13,174,842	13,244,342	13,244,342	13,244,342	n/a
3.	Less: Accumulated Depreciation (C)	5,967,824	6,036,672	6,066,440	6,135,034	6,203,811	6,272,769	6,341,727	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$7,176,345	$7,176,997	$7,108,402	$7,039,808	$7,040,532	$6,971,573	$6,902,615	n/a
6.	Average Net Investment		7,176,671	7,142,700	7,074,105	7,040,170	7,006,052	6,937,094	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		42,533	42,332	41,925	41,724	41,522	41,113	511,955
	b. Debt Component (Line 6 x 2.2507% x 1/12)		13,460	13,397	13,268	13,204	13,140	13,011	162,018
8.	*Investment Expenses*								
	a. Depreciation (E)		68,849	68,594	68,594	68,776	68,958	68,958	823,251
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)		(2,286)	(2,286)	(2,286)	(2,286)	(2,286)	(2,286)	(27,432)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$122,556	$122,037	$121,502	$121,419	$121,335	$120,797	$1,469,791

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 4.3685% 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 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 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)	26,814	27,058	27,303	27,547	27,791	28,036	28,280	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$32,052	$31,808	$31,563	$31,319	$31,075	$30,830	$30,586	n/a
6.	Average Net Investment		31,930	31,686	31,441	31,197	30,953	30,708	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		189	188	186	185	183	182	1,114
	b. Debt Component (Line 6 x 2.2507% x 1/12)		60	59	59	59	58	58	352
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)		$493	$492	$490	$488	$486	$484	$2,933

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 4.3685% 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 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 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)	28,280	28,524	28,769	29,013	29,257	29,502	29,746	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$30,586	$30,342	$30,097	$29,853	$29,609	$29,364	$29,120	n/a
6.	Average Net Investment		30,464	30,220	29,975	29,731	29,487	29,242	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		181	179	178	176	175	173	2,175
	b. Debt Component (Line 6 x 2.2507% x 1/12)		57	57	56	56	55	55	688
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)		$482	$480	$478	$476	$474	$472	$5,795

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 4.3685% 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 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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$508,290			$450,000			$958,290
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$12,931,422	13,439,712	13,439,712	13,439,712	13,889,712	13,889,712	13,889,712	n/a
3.	Less: Accumulated Depreciation (C)	1,672,418	1,712,059	1,752,631	1,793,204	1,834,822	1,877,487	1,920,151	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,259,004	$11,727,653	$11,687,081	$11,646,508	$12,054,890	$12,012,225	$11,969,561	n/a
6.	Average Net Investment		11,493,328	11,707,367	11,666,795	11,850,699	12,033,558	11,990,893	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		68,116	69,385	69,144	70,234	71,318	71,065	419,264
	b. Debt Component (Line 6 x 2.2507% x 1/12)		21,557	21,958	21,882	22,227	22,570	22,490	132,684
8.	Investment Expenses								
	a. Depreciation (E)		39,641	40,572	40,572	41,618	42,665	42,665	247,733
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$129,314	$131,915	$131,599	$134,080	$136,553	$136,220	$799,681

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 42-4P, 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 4.3685% 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 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 Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$120,000	$0	$0	$120,000	$0	$0	$1,198,290
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,889,712	14,009,712	14,009,712	14,009,712	14,129,712	14,129,712	14,129,712	n/a
3.	Less: Accumulated Depreciation (C)	1,920,151	1,963,065	2,006,227	2,049,389	2,092,800	2,136,459	2,180,119	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,969,561	$12,046,647	$12,003,485	$11,960,323	$12,036,912	$11,993,253	$11,949,593	n/a
6.	Average Net Investment		12,008,104	12,025,066	11,981,904	11,998,618	12,015,082	11,971,423	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		71,167	71,268	71,012	71,111	71,209	70,950	845,980
	b. Debt Component (Line 6 x 2.2507% x 1/12)		22,522	22,554	22,473	22,504	22,535	22,453	267,726
8.	Investment Expenses								
	a. Depreciation (E)		42,913	43,162	43,162	43,411	43,660	43,660	507,701
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	*Total System Recoverable Expenses (Lines 7 & 8)*		$136,603	$136,984	$136,647	$137,026	$137,404	$137,063	$1,621,408

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 4.3685% 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 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 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)	15,595	15,748	15,900	16,053	16,205	16,358	16,510	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$15,435	$15,282	$15,130	$14,977	$14,825	$14,672	$14,520	n/a
6.	Average Net Investment		15,359	15,206	15,054	14,901	14,748	14,596	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		91	90	89	88	87	87	533
	b. Debt Component (Line 6 x 2.2507% x 1/12)		29	29	28	28	28	27	169
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)		$272	$271	$270	$269	$268	$266	$1,616

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 4.3685% 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 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 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)	16,510	16,663	16,815	16,968	17,121	17,273	17,426	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$14,520	$14,367	$14,215	$14,062	$13,909	$13,757	$13,604	n/a
6.	Average Net Investment		14,443	14,291	14,138	13,986	13,833	13,681	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		86	85	84	83	82	81	1,033
	b. Debt Component (Line 6 x 2.2507% x 1/12)		27	27	27	26	26	26	327
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)		$265	$264	$263	$262	$260	$259	$3,189

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 4.3685% 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 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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$25,954	$0	$0	$16,750	$0	$0	$42,704
	c. Retirements								
	d. *Other (A)*								
2.	Plant-In-Service/Depreciation Base (B)	$764,665	790,619	790,619	790,619	807,369	807,369	807,369	n/a
3.	Less: Accumulated Depreciation (C)	470,269	479,563	488,858	498,152	507,646	517,191	526,685	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$294,396	$311,056	$301,761	$292,467	$299,723	$290,178	$280,684	n/a
6.	Average Net Investment		302,726	306,409	297,114	296,095	294,950	285,431	
7.	Return on Average Net Investment								
	a. *Equity Component grossed up for taxes (D)*		1,794	1,816	1,761	1,755	1,748	1,692	10,566
	b. Debt Component (Line 6 x 2.2507% x 1/12)		568	575	557	555	553	535	3,344
8.	Investment Expenses								
	a. Depreciation (E)		9,294	9,294	9,294	9,494	9,546	9,494	56,416
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	*Total System Recoverable Expenses (Lines 7 & 8)*		$11,656	$11,685	$11,612	$11,804	$11,847	$11,721	$70,325

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 4.3685% 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 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 Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$16,750	$0	$0	$16,750	$0	$0	$76,204
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$807,369	824,119	824,119	824,119	840,869	840,869	840,869	n/a
3.	Less: Accumulated Depreciation (C)	526,685	536,378	546,071	555,764	565,657	575,549	585,442	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$280,684	$287,741	$278,048	$268,355	$275,212	$265,320	$255,427	n/a
6.	Average Net Investment		284,212	282,894	273,201	271,783	270,266	260,373	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,684	1,677	1,619	1,611	1,602	1,543	20,301
	b. Debt Component (Line 6 x 2.2507% x 1/12)		533	531	512	510	507	488	6,425
8.	Investment Expenses								
	a. Depreciation (E)		9,693	9,693	9,693	9,893	9,893	9,893	115,173
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,911	$11,900	$11,825	$12,013	$12,001	$11,924	$141,899

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 4.3685% 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 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 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)	34,536	34,850	35,164	35,478	35,792	36,107	36,421	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$83,258	$82,944	$82,630	$82,316	$82,002	$81,687	$81,373	n/a
6.	Average Net Investment		83,101	82,787	82,473	82,159	81,845	81,530	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		493	491	489	487	485	483	2,927
	b. Debt Component (Line 6 x 2.2507% x 1/12)		156	155	155	154	154	153	926
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)		$962	$960	$958	$955	$953	$950	$5,738

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 4.3685% 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 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 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)	36,421	36,735	37,049	37,363	37,677	37,991	38,305	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$81,373	$81,059	$80,745	$80,431	$80,117	$79,803	$79,489	n/a
6.	Average Net Investment		81,216	80,902	80,588	80,274	79,960	79,646	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		481	479	478	476	474	472	5,787
	b. Debt Component (Line 6 x 2.2507% x 1/12)		152	152	151	151	150	149	1,831
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)		$948	$945	$943	$940	$938	$936	$11,388

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 4.3685% 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 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 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)	311,655	314,684	317,713	320,742	323,771	326,800	329,828	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$552,605	$549,576	$546,547	$543,518	$540,489	$537,460	$534,432	n/a
6.	Average Net Investment		551,091	548,062	545,033	542,004	538,975	535,946	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,266	3,248	3,230	3,212	3,194	3,176	19,327
	b. Debt Component (Line 6 x 2.2507% x 1/12)		1,034	1,028	1,022	1,017	1,011	1,005	6,116
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)		$7,329	$7,305	$7,281	$7,258	$7,234	$7,210	$43,617

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 4.3685% 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 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 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)	329,828	332,857	335,886	338,915	341,944	344,973	348,002	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$534,432	$531,403	$528,374	$525,345	$522,316	$519,287	$516,258	n/a
6.	Average Net Investment		532,917	529,888	526,859	523,830	520,802	517,773	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,158	3,140	3,122	3,105	3,087	3,069	38,008
	b. Debt Component (Line 6 x 2.2507% x 1/12)		1,000	994	988	982	977	971	12,028
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)		$7,187	$7,163	$7,140	$7,116	$7,092	$7,069	$86,384

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 4.3685% 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 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 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)	$311,009	311,009	311,009	311,009	311,009	311,009	311,009	n/a
3.	Less: Accumulated Depreciation (C)	284,269	288,089	291,909	295,729	299,549	303,369	307,189	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$26,740	$22,920	$19,100	$15,280	$11,460	$7,640	$3,820	n/a
6.	Average Net Investment		24,830	21,010	17,190	13,370	9,550	5,730	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		147	125	102	79	57	34	543
	b. Debt Component (Line 6 x 2.2507% x 1/12)		47	39	32	25	18	11	172
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)		$4,014	$3,984	$3,954	$3,924	$3,894	$3,865	$23,635

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 4.3685% 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 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 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)*	$311,009	311,009	311,009	311,009	311,009	311,009	311,009	n/a
3.	Less: Accumulated Depreciation (C)	307,189	311,009	311,009	311,009	311,009	311,009	311,009	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$3,820	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		1,910	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		11	0	0	0	0	0	555
	b. Debt Component (Line 6 x 2.2507% x 1/12)		4	0	0	0	0	0	176
8.	Investment Expenses								
	a. Depreciation (E)		3,820	0	0	0	0	0	26,740
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,835	$0	$0	$0	$0	$0	$27,470

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 4.3685% 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 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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$300,583	$0	$0	$0	$0	$0	$300,583
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$1,864,578	2,165,161	2,165,161	2,165,161	2,165,161	2,165,161	2,165,161	n/a
3.	Less: Accumulated Depreciation (C)	305,981	314,466	323,530	332,594	341,658	350,722	359,785	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,558,597	$1,850,695	$1,841,631	$1,832,567	$1,823,503	$1,814,440	$1,805,376	n/a
6.	Average Net Investment		1,704,646	1,846,163	1,837,099	1,828,035	1,818,971	1,809,908	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		10,103	10,941	10,888	10,834	10,780	10,727	64,273
	b. Debt Component (Line 6 x 2.2507% x 1/12)		3,197	3,463	3,446	3,429	3,412	3,395	20,340
8.	Investment Expenses								
	a. Depreciation (E)		8,485	9,064	9,064	9,064	9,064	9,064	53,804
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$21,785	$23,468	$23,397	$23,327	$23,256	$23,185	$138,418

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 4.3685% 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 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 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	$300,583
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,165,161	2,165,161	2,165,161	2,165,161	2,165,161	2,165,161	2,165,161	n/a
3.	Less: Accumulated Depreciation (C)	$359,785	368,849	377,913	386,977	396,041	405,105	414,168	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,805,376	$1,796,312	$1,787,248	$1,778,184	$1,769,120	$1,760,056	$1,750,993	n/a
6.	Average Net Investment		1,800,844	1,791,780	1,782,716	1,773,652	1,764,588	1,755,525	
7.	Return on Average Net Investment								
	Equity Component grossed up for taxes (D)		10,673	10,619	10,565	10,512	10,458	10,404	127,505
	Debt Component (Line 6 x 2.2507% x 1/12)		3,378	3,361	3,344	3,327	3,310	3,293	40,351
8.	Investment Expenses								
	a. Depreciation (E)		9,064	9,064	9,064	9,064	9,064	9,064	108,187
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$23,114	$23,044	$22,973	$22,902	$22,831	$22,761	$276,043

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 4.3685% 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 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 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	828,789	828,789	n/a
3.	Less: Accumulated Depreciation (C)	27,532	29,742	31,952	34,162	36,372	38,583	40,793	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$801,257	$799,047	$796,837	$794,627	$792,417	$790,207	$787,996	n/a
6.	Average Net Investment		800,152	797,942	795,732	793,522	791,312	789,101	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		4,742	4,729	4,716	4,703	4,690	4,677	28,257
	b. Debt Component (Line 6 x 2.2507% x 1/12)		1,501	1,497	1,492	1,488	1,484	1,480	8,942
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)		$6,999	$6,982	$6,965	$6,947	$6,930	$6,913	$41,736

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 4.3685% 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 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 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)	$40,793	43,003	45,213	47,423	49,633	51,843	54,053	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$787,996	$785,786	$783,576	$781,366	$779,156	$776,946	$774,736	n/a
6.	Average Net Investment		786,891	784,681	782,471	780,261	778,051	775,841	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		4,664	4,650	4,637	4,624	4,611	4,598	56,042
	b. Debt Component (Line 6 x 2.2507% x 1/12)		1,476	1,472	1,468	1,463	1,459	1,455	17,735
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)		$6,896	$6,878	$6,861	$6,844	$6,827	$6,809	$82,851

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 4.3685% 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 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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$405,000	$0	$0	$0	$0	$0	$405,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$405,000	810,000	810,000	810,000	810,000	810,000	810,000	n/a
3.	Less: Accumulated Depreciation (C)	3,038	4,860	7,290	9,720	12,150	14,580	17,010	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$401,962	$805,140	$802,710	$800,280	$797,850	$795,420	$792,990	n/a
6.	Average Net Investment		603,551	803,925	801,495	799,065	796,635	794,205	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,577	4,765	4,750	4,736	4,721	4,707	27,256
	b. Debt Component (Line 6 x 2.2507% x 1/12)		1,132	1,508	1,503	1,499	1,494	1,490	8,626
8.	Investment Expenses								
	a. Depreciation (E)		1,822	2,430	2,430	2,430	2,430	2,430	13,972
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$6,531	$8,702	$8,683	$8,664	$8,645	$8,627	$49,852

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 4.3685% 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 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 Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$405,000
	b. Clearings to Plant								
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$810,000	810,000	810,000	810,000	810,000	810,000	810,000	n/a
3.	Less: Accumulated Depreciation (C)	$17,010	19,440	21,870	24,300	26,730	29,160	31,590	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$792,990	$790,560	$788,130	$785,700	$783,270	$780,840	$778,410	n/a
6.	Average Net Investment		791,775	789,345	786,915	784,485	782,055	779,625	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		4,693	4,678	4,664	4,649	4,635	4,621	55,195
	b. Debt Component (Line 6 x 2.2507% x 1/12)		1,485	1,480	1,476	1,471	1,467	1,462	17,467
8.	Investment Expenses								
	a. Depreciation (E)		2,430	2,430	2,430	2,430	2,430	2,430	28,552
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,608	$8,589	$8,570	$8,551	$8,532	$8,513	$101,215

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 4.3685% 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 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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$3,566,277	$172,000	$167,000	$829,500	$167,000	$167,000	$5,068,777
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$4,978,601	8,544,878	8,716,878	8,883,878	9,713,378	9,880,378	10,047,378	n/a
3.	Less: Accumulated Depreciation (C)	44,500	67,464	97,362	127,570	159,387	192,814	226,547	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$4,934,101	$8,477,414	$8,619,516	$8,756,308	$9,553,991	$9,687,564	$9,820,831	n/a
6.	Average Net Investment		6,705,757	8,548,465	8,687,912	9,155,150	9,620,778	9,754,198	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		39,742	50,663	51,490	54,259	57,019	57,809	310,982
	b. Debt Component (Line 6 x 2.2507% x 1/12)		12,577	16,033	16,295	17,171	18,045	18,295	98,416
8.	*Investment Expenses*								
	a. Depreciation (E)		22,964	29,897	30,208	31,817	33,427	33,733	182,047
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$75,284	$96,594	$97,993	$103,248	$108,490	$109,837	$591,446

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 4.3685% 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 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 Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	*Investments*								
	a. Expenditures/Additions								
	b. Clearings to Plant		$829,500	$167,000	$167,000	$829,500	$167,000	$667,000	$7,895,777
	c. Retirements								
	d. Other (A)								
2.	Plant-in-Service/Depreciation Base (B)	$10,047,378	10,876,878	11,043,878	11,210,878	12,040,378	12,207,378	12,874,378	n/a
3.	*Less: Accumulated Depreciation (C)*	$226,547	261,889	298,841	336,099	374,966	415,443	456,893	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$9,820,831	$10,614,989	$10,745,037	$10,874,779	$11,665,412	$11,791,935	$12,417,485	n/a
6.	Average Net Investment		10,217,910	10,680,013	10,809,908	11,270,095	11,728,673	12,104,710	
7.	*Return on Average Net Investment*								
	a. Equity Component grossed up for taxes (D)		60,558	63,296	64,066	66,793	69,511	71,740	706,947
	b. Debt Component (Line 6 x 2.2507% x 1/12)		19,165	20,031	20,275	21,138	21,998	22,703	223,726
8.	Investment Expenses								
	a. Depreciation (E)		35,342	36,952	37,258	38,867	40,477	41,450	412,393
	b. Amortization (F)								
	c. *Dismantlement*								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$115,064	$120,279	$121,599	$126,799	$131,986	$135,893	$1,343,066

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 4.3685% 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 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 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	(1,484,209)	(1,448,346)	(1,412,483)	(1,376,620)	(1,340,757)	(1,304,894)	(1,469,031)		
2	Total Working Capital	($1,484,209)	($1,448,346)	($1,412,483)	($1,376,620)	($1,340,757)	($1,304,894)	($1,469,031)		
3	Average Net Working Capital Balance		(1,466,278)	(1,430,415)	(1,394,552)	(1,358,689)	(1,322,826)	(1,386,963)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(8,690)	(8,478)	(8,265)	(8,052)	(7,840)	(8,220)	(49,545)	
	b Debt Component (Line 6 x 2.2507% x 1/12)		(2,750)	(2,683)	(2,616)	(2,548)	(2,481)	(2,601)	(15,679)	
5	Total Return Component		($11,440)	($11,160)	($10,881)	($10,601)	($10,321)	($10,821)	($65,224)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(215,178)	
	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)		($35,863)	($35,863)	($35,863)	($35,863)	($35,863)	($35,863)	($215,178)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(47,303)	(47,023)	(46,744)	(46,464)	(46,184)	(46,684)		
	a Recoverable Costs Allocated to Energy		(47,303)	(47,023)	(46,744)	(46,464)	(46,184)	(46,684)		
	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)*		(46,611)	(46,336)	(46,060)	(45,784)	(45,509)	(46,002)	(276,301)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($46,611)	($46,336)	($46,060)	($45,784)	($45,509)	($46,002)	($276,301)	

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 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 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	(1,469,031)	(1,433,169)	(1,397,306)	(1,361,444)	(1,325,581)	(1,289,719)	(1,253,856)		
2	Total Working Capital	($1,469,031)	($1,433,169)	($1,397,306)	($1,361,444)	($1,325,581)	($1,289,719)	($1,253,856)		
3	Average Net Working Capital Balance		(1,451,100)	(1,415,237)	(1,379,375)	(1,343,512)	(1,307,650)	(1,271,787)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(8,600)	(8,388)	(8,175)	(7,962)	(7,750)	(7,537)	(97,957)	
	b Debt Component (Line 6 x 2.2507% x 1/12)		(2,722)	(2,654)	(2,587)	(2,520)	(2,453)	(2,385)	(31,000)	
5	Total Return Component		($11,322)	($11,042)	($10,762)	($10,482)	($10,203)	($9,923)	($128,958)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(35,863)	(430,353)	
	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)		($35,863)	($35,863)	($35,863)	($35,863)	($35,863)	($35,863)	($430,353)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		($47,184)	($46,904)	($46,625)	($46,345)	($46,065)	($45,785)		
	a Recoverable Costs Allocated to Energy		(47,184)	(46,904)	(46,625)	(46,345)	(46,065)	(45,785)		
	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)		(46,494)	(46,218)	(45,943)	(45,667)	(45,391)	(45,116)	(551,131)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($46,494)	($46,218)	($45,943)	($45,667)	($45,391)	($45,116)	($551,131)	

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 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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$700,000	$0	$1,130,000	$0	$0	$1,830,000
	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	$660,800	660,800	1,360,800	1,360,800	2,490,800	2,490,800	2,490,800	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$660,800	$660,800	$1,360,800	$1,360,800	$2,490,800	$2,490,800	$2,490,800	n/a
6.	Average Net Investment		660,800	1,010,800	1,360,800	1,925,800	2,490,800	2,490,800	
7.	*Return on Average Net Investment*								
	a. Equity Component grossed up for taxes (D)		3,916	5,991	8,065	11,413	14,762	14,762	58,909
	b. Debt Component (Line 6 x 2.2507% x 1/12)		1,239	1,896	2,552	3,612	4,672	4,672	18,643
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)		$5,156	$7,886	$10,617	$15,025	$19,434	$19,434	$77,552

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 42-8P, 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 42-8P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the 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 Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$2,810,000	$560,000	$0	$6,370,000	$11,570,000
	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	$2,490,800	2,490,800	2,490,800	5,300,800	5,860,800	5,860,800	12,230,800	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,490,800	$2,490,800	$2,490,800	$5,300,800	$5,860,800	$5,860,800	$12,230,800	n/a
6.	Average Net Investment		2,490,800	2,490,800	3,895,800	5,580,800	5,860,800	9,045,800	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		14,762	14,762	23,089	33,075	34,735	53,611	232,943
	b. Debt Component (Line 6 x 2.2507% x 1/12)		4,672	4,672	7,307	10,467	10,992	16,966	73,719
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)		$19,434	$19,434	$30,396	$43,542	$45,727	$70,577	$306,662

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 42-8P, 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 42-8P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

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

Return on Capital Investments, Depreciation and Taxes
For Project: 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		$913,659	$766,500	$1,073,100	$1,216,500	$1,369,800	$1,319,800	$6,659,359
	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	$968,141	1,881,800	2,648,300	3,721,400	4,937,900	6,307,700	7,627,500	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$968,141	$1,881,800	$2,648,300	$3,721,400	$4,937,900	$6,307,700	$7,627,500	n/a
6.	Average Net Investment		1,424,971	2,265,050	3,184,850	4,329,650	5,622,800	6,967,600	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		8,445	13,424	18,875	25,660	33,324	41,294	141,023
	b. Debt Component (Line 6 x 2.2507% x 1/12)		2,673	4,248	5,973	8,121	10,546	13,068	44,629
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)		$11,118	$17,672	$24,849	$33,781	$43,870	$54,363	$185,653

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 42-8P, 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 42-8P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

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

Return on Capital Investments, Depreciation and Taxes
For Project: 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		$2,236,134	$6,843,328	$3,720,180	$3,320,180	$3,080,180	$2,983,580	$28,842,941
	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	$7,627,500	9,863,634	16,706,962	20,427,142	23,747,322	26,827,502	29,811,082	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$7,627,500	$9,863,634	$16,706,962	$20,427,142	$23,747,322	$26,827,502	$29,811,082	n/a
6.	Average Net Investment		8,745,567	13,285,298	18,567,052	22,087,232	25,287,412	28,319,292	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		51,832	78,737	110,040	130,902	149,868	167,837	830,239
	b. Debt Component (Line 6 x 2.2507% x 1/12)		16,403	24,918	34,824	41,426	47,429	53,115	262,744
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)		$68,235	$103,654	$144,864	$172,329	$197,297	$220,952	$1,092,983

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 42-8P, 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 42-8P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-8P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

FOR 2004

Project No.	PLANT NAME	PROJECTED JANUARY PLANT IN SERVICE (BOM)	PROJECTED DECEMBER PLANT IN SERVICE (EOM)
02	RIVIERA UNIT 3	$3,846,591.65	$3,846,591.65
	RIVIERA UNIT 4	$3,272,970.68	$3,272,970.68
	PT EVERGLADES UNIT 1	$2,700,574.97	$2,700,574.97
	PT EVERGLADES UNIT 2	$2,377,900.75	$2,377,900.75
	TURKEY UNIT 1	$2,961,524.84	$2,961,524.84
	TURKEY UNIT 2	$2,451,904.92	$2,451,904.92
	TOTAL FOR PROJECT 2	**$17,611,467.81**	**$17,611,467.81**
4	CAPE CANAVERAL COMMON	$17,254.20	$17,254.20
	PT EVERGLADES COMMON	$19,812.30	$19,812.30
	TURKEY COMMON	$21,799.28	$21,799.28
	TOTAL FOR PROJECT 4	**$58,865.78**	**$58,865.78**
7	ST. LUCIE UNIT 1	$31,030.00	$31,030.00
	TOTAL FOR PROJECT 7	**$31,030.00**	**$31,030.00**
8	MARTIN COMMON	$ 23,107.32	$ 23,107.32
	MARTIN COMMON	$ 657,953.94	$ 734,157.94
	MARTIN COM PPBT	$ 15,228.31	$ 15,228.31
	MARTIN COM PPBT	$ 53,549.84	$ 53,549.84
	CAPE CANAVERAL FT	$ 4,362.96	$ 4,362.96
	SANFORD	$ 5,094.50	$ 5,094.50
	TURKEY COMMON	$ 5,368.46	$ 5,368.46
	TOTAL FOR PROJECT 8	**$764,665.33**	**$840,869.33**
10	ST. LUCIE COMMON	$117,793.83	$117,793.83
	TOTAL FOR PROJECT 10	**$117,793.83**	**$117,793.83**
12	SCHERER COMMON	$9,936.72	$9,936.72
	SCHERER COMMON	$524,872.97	$524,872.97
	SCHERER COMMON	$328,761.62	$328,761.62
	SCHERER COMMON	$689.11	$689.11
	TOTAL FOR PROJECT 12	**$864,260.42**	**$864,260.42**
17	MARTIN EQUIPM YAR	$311,008.58	$311,008.58
	TOTAL FOR PROJECT 17	**$311,008.58**	**$311,008.58**
20	CAPE CANAVERAL COMMON	$831,500.94	$956,500.94
	RIVIERA COMMON	$560,786.81	$560,786.81
	PT EVERGLADES COMMON	$362,290.34	$427,873.34
	MARTIN COMMON	$110,000.00	$220,000.00
	TOTAL FOR PROJECT 20	**$1,864,578.09**	**$2,165,161.09**
21	ST LUCIE COMMON	$828,789.34	$828,789.34
	TOTAL FOR PROJECT 21	**$828,789.34**	**$828,789.34**

PROJECT NO 3 b

FOR 2004

PLANT NAME	PLANT ACCOUNT	DEPRECIATION RATE/ AMORTIZATION PERIOD	PROJECTED JANUARY PLANT IN SERVICE (BOM)	PROJECTED DECEMBER PLANT IN SERVICE (EOM)
PUTNAM COMMON	341	4.20%	$ 82,857.82	$ 82,857.82
PUTNAM COMMON	343	5.60%	$ 3,138.97	$ 3,138.97
PUTNAM UNIT 1	343	6.00%	$ 346,065.01	$ 366,365.01
PUTNAM UNIT 2	343	6.30%	$ 358,915.31	$ 379,215.31
SANFORD COMMON	312	3.50%	$ 5,168.21	$ 5,168.21
SANFORD UNIT 3	311	2.40%	$ 54,282.08	$ 54,282.08
SANFORD UNIT 3	312	2.40%	$ 158,107.02	$ 173,407.02
SANFORD UNIT 3 RL	312	0.00%	$ 442,603.11	$ 442,603.11
SANFORD UNIT 4 RL	312	0.00%	$ 41,859.48	$ 41,859.48
CAPE CANAVERAL COMMON	311	4.90%	$ 59,227.10	$ 59,227.10
CAPE CANAVERAL COMMON	312	8.50%	$ 8,132.66	$ 8,132.66
CAPE CANAVERAL U1	312	8.80%	$ 502,857.87	$ 513,082.87
CAPE CANAVERAL U2	312	8.30%	$ 519,956.24	$ 530,181.24
MARTIN COM FOSSIL	312	4.60%	$ 10,093.81	$ 10,093.81
MARTIN UNIT 1	311	3.30%	$ 36,810.86	$ 36,810.86
MARTIN UNIT 1	312	4.80%	$ 553,158.17	$ 561,033.17
MARTIN UNIT 2	311	3.30%	$ 36,845.37	$ 36,845.37
MARTIN UNIT 2	312	4.90%	$ 551,568.96	$ 559,443.96
MARTIN UNIT 3	343	5.70%	$ 386,605.43	$ 406,905.43
MARTIN UNIT 4	343	5.50%	$ 380,685.87	$ 400,985.87
RIVIERA COMMON	311	5.20%	$ 60,973.18	$ 60,973.18
RIVIERA COMMON	312	8.90%	$ 8,166.97	$ 8,166.97
RIVIERA UNIT 3	312	8.90%	$ 446,895.32	$ 457,020.32
RIVIERA UNIT 4	312	7.90%	$ 430,924.90	$ 441,049.90
FORT MYERS CT's	343	5.50%	$ 64,167.00	$ 64,167.00
MANATEE COMMON	312	4.60%	$ 9,359.98	$ 9,359.98
MANATEE UNIT 1	311	2.90%	$ 56,430.25	$ 56,430.25
MANATEE UNIT 1	312	4.00%	$ 481,325.93	$ 491,550.93
MANATEE UNIT 2	311	3.00%	$ 56,332.75	$ 56,332.75
MANATEE UNIT 2	312	4.20%	$ 517,425.20	$ 527,650.20
FT LAUDERDALE COMMON	341	5.30%	$ 58,859.79	$ 58,859.79
FT LAUDERDALE U4	343	6.50%	$ 458,222.61	$ 478,472.61
FT LAUDERDALE U5	343	6.60%	$ 466,221.29	$ 486,471.29
PT EVERGLADES COMMON	311	5.80%	$ 127,911.34	$ 127,911.34
PT EVERGLADES COMMON	312	7.70%	$ 19,111.95	$ 19,111.95
PT EVERGLADES UT1	312	6.10%	$ 469,449.32	$ 486,699.32
PT EVERGLADES UT2	312	6.50%	$ 490,902.48	$ 508,152.48
PT EVERGLADES UT3	312	7.80%	$ 503,843.57	$ 506,843.57
PT EVERGLADES UT4	312	8.40%	$ 512,009.55	$ 515,009.55
CUTLER COMMON	311	5.20%	$ 64,883.87	$ 64,883.87
CUTLER COMMON	312	8.80%	$ 6,408.88	$ 6,408.88
CUTLER UNIT 5	312	5.00%	$ 310,051.62	$ 320,126.62
CUTLER UNIT 6	312	5.10%	$ 322,119.14	$ 332,194.14
TURKEY UNIT 1	312	8.80%	$ 554,555.15	$ 564,280.15
TURKEY UNIT 2	312	6.70%	$ 513,659.44	$ 523,384.44
TURKEY COMMON	311	4.30%	$ 59,056.19	$ 59,056.19
TURKEY COMMON	312	6.90%	$ 8,168.05	$ 8,168.05
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	$ 106,814.52
SJRPP UNIT 2	312	4.20%	$ 106,783.43	$ 106,783.43
SCHERER UNIT 4	312	4.50%	$ 537,039.34	$ 537,039.34
POWER RESCOU-JUNO	391	3 yr amort	$ -	$ -
POWER RESCOU-JUNO	394	7 yr amort	$ 38,826.87	$ -
POWER RESCOU-JUNO	395	7 yr amort	$ 473,947.53	$ 473,947.53
TOTAL FOR PROJECT 3			**$ 12,989,168.27**	**$ 13,244,341.40**

PROJECT NO. 5b — **FOR 2004**

PLANT NAME	PLANT ACCOUNT	DEPRECIATION RATE	PROJECTED JANUARY PLANT IN SERVICE (BOM)	PROJECTED DECEMBER PLANT IN SERVICE (EOM)
PUTNAM COMMON	342	4.00%	$ 749,025.94	$ 749,025.94
SANFORD COMMON	311	2.80%	$ -	$ -
SANFORD UNIT 3	311	5.80%	$ 796,754.11	$ 796,754.11
CAPE CANAVERAL COMMON	311	4.90%	$ 268,748.69	$ 268,748.69
CAPE CANAVERAL FT	311	4.90%	$ 632,888.19	$ 632,888.19
MARTIN COM PPBT	311	3.60%	$ 638,132.62	$ 638,132.62
MARTIN COM FOSSIL	311	3.60%	$ 407,224.94	$ 407,224.94
MARTIN COM FOP	311	3.60%	$ 65,092.76	$ 65,092.76
MARTIN UNIT 1	311	3.30%	$ 176,338.83	$ 176,338.83
RIVIERA COMMON	311	5.20%	$ 727,734.38	$ 952,734.38
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
MANATEE COMMON	311	3.50%	$ 30,323.73	$ 30,323.73
MANATEE COMMON	312	4.60%	$ 174,543.23	$ 309,543.23
PORT MANATEE TERM	311	3.50%	$ 3,006,557.60	$ 3,006,557.60
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
FT LAUDERDALE COMMON	342	4.30%	$ 898,110.65	$ 898,110.65
FT LAUDERDALE GTS	342	0.70%	$ 584,290.23	$ 584,290.23
PT EVERGLADES FOT	311	5.80%	$ 1,478,078.22	$ 2,154,078.22
PT EVERGLADES GTU	342	1.40%	$ 1,750,217.58	$ 1,912,507.58
TURKEY COMMON	311	4.30%	$ 87,560.23	$ 87,560.23
TURKEY UNIT 2	311	5.20%	$ 42,158.96	$ 42,158.96
SJRPP COMMON	311	3.40%	$ 42,091.24	$ 42,091.24
TOTAL FOR PROJECT 5			**$ 12,931,422.34**	**$ 14,129,712.34**
MARTIN TERMINAL	311	3.60%	$405,000.00	$ 810,000.00
TOTAL FOR PROJECT 22			**$405,000.00**	**$ 810,000.00**
PUTNAM COMMON	342	4.00%	$ 636,125.00	$ 1,641,886.00
SANFORD COMMON	342	4.50%	$ 30,625.00	$ 67,451.00
CAPE CANAVERAL COMMON	311	4.90%	**$ 71,875.00**	**$ 179,180.00**
RIVIERA COMMON	311	5.20%	$ 66,875.00	$ 165,637.00
FORT MYERS COMMON	342	4.50%	$ 668,375.00	$ 1,729,240.00
FT LAUDERDALE COMMON	342	4.30%	**$ 965,125.00**	**$ 2,533,016.00**
PT EVERGLADES COMMON	311	5.80%	**$ 884,375.00**	**$ 2,314,297.00**
TURKEY COMMON	311	4.30%	$ 26,875.00	$ 57,293.00
ST LUCIE COMMON	321	3.20%	$ -	$ 500,000.00
JUNO OFFICE	390	2.80%	$ 50,000.00	$ 50,000.00
GENERAL OFFICE	390	2.80%	$ 50,000.00	$ 50,000.00
POWER SUPPLY SUBSTATIONS	352/361	2.20%	$ 1,528,351.00	$ 3,586,378.23
TOTAL FOR PROJECT 23			**$ 4,978,601.00**	**$ 12,874,378.23**

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, 2003 to December 31, 2003)
The monthly fees for 2002 emissions at Scherer have been paid and continue to be paid in 2003. 2002 air operating permit fees for the Florida facilities were calculated in January 2003 utilizing 2002 operating information. They were paid to the FDEP in March 2003.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $237,723 or 10.8% lower than previously projected. Permit fees are based on tons of pollutants discharged from the fossil fuel fired power plants. These emissions are proportionate to the amount of time and the type of fuel used at each plant. As a result of the completion of the Fort Myers Plant and Sanford Plant repowerings, less residual oil and more natural gas was burned than expected at these sites. Because natural gas produces fewer emissions than residual oil, permit fees were less than projected.

Project Progress Summary:

The monthly fees for 2002 emissions at Scherer have been paid and continue to be paid in 2003. 2002 air operating permit fees for the Florida facilities were calculated in January 2003 utilizing 2002 operating information. They were paid to the FDEP in March 2003.

Project Projections:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $2,061,980.

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, 2003 to December 31, 2003)
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, 2003 to December 31, 2003)
Project expenditures are estimated to be $6,549 or 1.0% lower than previously projected.

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 2004 through December 2004 are expected to be $632,640.

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, 2003 to December 31, 2003)
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 2003 tank registration fees have been paid.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $127,177 or 71.0% higher than previously projected. This project includes performing the required repairs identified during a tank inspection. The variance is primarily due to an updated estimate of the costs associated with the required repairs, 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 2004 through December 2004 are expected to be $460,500.

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, 2003 to December 31, 2003)
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, 2003 to December 31, 2003)
Project expenditures are estimated to be $18,888 or 12.6% higher than previously projected. This variance is primarily due to an increase in the required maintenance and operation of spill boats and corporate spill equipment.

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 2004 through December 2004 are expected to be $165,996.

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, 2003 to December 31, 2003)
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 3013 order for site wide corrective action activities at the Manatee, Sanford, Turkey Point and St. Lucie Power Plants.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $2,498 or 5.0% higher than previously projected.

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.

Project Projection:
Estimated project expenditures for the period of January 2004 through December 2004 are expected to be $50,004.

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, 2003 to December 31, 2003)
The NPDES permit fees were paid to the FDEP during the month of January.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $10,643 or 9.4% higher than previously projected.

Project Progress Summary:

The NPDES permit fees were paid to the FDEP during the month of January.

Project Projections:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $134,205.

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, 2003 to December 31, 2003)
Ash de-watering has been completed at Riviera. Currently processing material at Manatee, which will be completed in August 2003. Ash de-watering is planned for the rest of 2003 at Martin, Turkey Point, and Cape Canaveral.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $39,862 or 14.8% lower than previously projected. This variance is primarily due an increase in the time needed to complete the clean out of the drying basin at the Manatee Plant. The increase in work time at the Manatee Plant has delayed the work scheduled at the Port Everglades plant to 2004.

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 2004 through December 2004 are expected to be $288,000.

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, 2003 to December 31, 2003)
Plan development started in 1997 and field work is planned to continue through 2003. The majority of the completed work has been in Dade and Broward counties. Regasketing and encapsulation work has started in Palm Beach County and remediation work is being performed throughout the FPL service territory.

A total of 709 transformer locations have been remediated since 1997, this completes the remediation phase of the project. A total of 387 transformers have been regasketed and 789 transformers have been encapsulated.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be:

- 19a $1,000,300 No variance is anticipated
- 19b $677,900 No variance is anticipated
- 19c ($560,232) No variance is anticipated

Personnel resources were reassigned to perform critical system reliability activities. This project was affected by these reliability activities, extending the required work to 2003.

Project Progress Summary:

Remediation phase of the project is complete. The regasketing and encapsulation phase of the project continues.

Project Projections:

Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $1,362,028.

Project Title: Wastewater/Stormwater Discharge Elimination Project
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, 2003 to December 31, 2003)
Work on this project has been completed as follows. The Riviera plant has completed activities totaling approximately $25,000 for the year. The Manatee plant is scheduled to spend approximately $10,000 by the end of 2003. The activities at the Manatee plant are planned to be completed in the 4th quarter of 2003, during a scheduled outage.

Project Fiscal Expenditures:
(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $52,389 or 61.6% lower than projected. This variance is primarily due to timing differences. Work that was to be performed at the Port Everglades plant this year has been deferred to 2004.

Project Progress Summary:
During detailed engineering and design, industry research revealed that there is limited information regarding the minimum quality of reuse water needed so as not to adversely affect the performance and/or reliability of the power generating equipment. Furthermore, bench testing at our Putnam Plant to make demineralized water from stormwater proved unsuccessful and the water treatment vendor could not readily suggest a workable alternative to the original proposal. Because of these limitations and unknowns, FPL feels it would be prudent to construct reuse systems on a limited basis and monitor the effects of the reuse water on plant equipment. It is expected that the trial implementation would need to operate for at least two (2) years before accurate conclusions could be drawn regarding acceptable reuse water quality. Accordingly, the majority of the expenditures for field-erected storage tanks and reuse pump & piping systems have been pushed beyond the year 2001.

FPL will continue to work with the FDEP to evaluate the compliance risk associated with its wastewater systems and effect additional future upgrades as necessary.

Project Projections:
Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $50,000.

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, 2003 to December 31, 2003)
The final draft of the Pipeline Integrity Management plan was approved and is in force. Plans are underway to solicit bids for the performance of the first of the baseline assessments on the Martin 18" pipeline.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $127,216 or 63.6% lower than projected. The development of the baseline assessment plan required less contractor utilization than originally expected.

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 and this should begin in January 2004.

Project Projections:

Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $40,008 of O&M.

Project Title: SPCC (spill prevention, control, and countermeasures) – O&M
Project No.23
Project Description:

The SPCC Program was first established by the EPA 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, 2003 to December 31, 2003)
The project is moving toward construction starting in September. The work scope is developed and bids have been solicited. Initial studies to confirm compliance methods are also complete.

Project Fiscal Expenditures:
(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $98,739 or 56.4% lower than projected. This variance is primarily due to a change in the implementation date of the SPCC plans from August 2003 to February 2005 by the EPA.

Project Progress Summary:
Initial studies have been completed for the compliance methods that will be used. The EPA changed the implementation dates from August 2003 to February 2005; therefore the schedule has slowed down a little from the initial push.

Project Projections:
Estimated project expenditures for the period January 2004 through December 2004 are expected to be $250,000 of O&M.

Project Title: Reburn NOx Control Technology at Manatee Plant – O&M
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, 2003 to December 31, 2003)
The Manatee Reburn project 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, 2003 to December 31, 2003)
None

Project Progress Summary:
The engineers are in the process of preparing and reviewing the request for proposals for the Manatee Reburn project.

Project Projections:
Estimated project expenditures for the period January 2004 through December 2004 are expected to be $0 of O&M.

Project Title: Underground Storage Tanks – 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. Exhibit RRL- 2 provides a list and description of FPL's existing UST systems.
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, 2003 to December 31, 2003)
Initial review of the scope of work has been completed.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
None

Project Progress Summary:
Initial review of the scope of work has been completed.

Project Projections:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $148,050 of O&M.

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, 2003 to December 31, 2003)
The project at Sanford is currently operational and the project at Cape Canaveral is under construction and should be complete by the end of the year

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures will be $93,000 for O&M.

Project Progress Summary:

(January 2003 - December 2003)
Negotiations have taken place between Brevard County and Cape Canaveral for the purchase of water and negotiations are taking place in regards to the filtration process. The Sanford plant is complete with their negotiations and U.S. Filter if the vendor that was selected for the filtration process.

Project Projections:

Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $370,200 of O&M.

Project Title: Low NO_x Burner Technology (LNBT) – Capital (Florida Facilities)
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, 2003 to December 31, 2003)
All six units are in service and operational.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are estimated to be $2,072,617 no variance anticipated.

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 expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $1,932,576.

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, 2003 to December 31, 2003)
NOx Continuos Emission Monitoring Analyzers were installed at all Utility facilities with the exception of Putnam, Martin 3/4 and Lauderdale Plants. These installations will be performed during the 4th quarter of 2003 and will conclude the NOx analyzer portion of the project. Martin Units 1 & 2 NOx installations were performed in mid 2002 as part of a separate project.

Project Fiscal Expenditures:
(January 1, 2003 to December 31, 2003)

The variance is $30,835, or 2.0% lower than projected. The replacement of the CEMS Data Acquisition and Handling System (DAHS) servers and associated software upgrades is currently under review for the best technology and lowest price compliance option. An analysis is being developed based on the current system's recent failures. If the analysis shows that the replacement of the current servers and software upgrades is necessary, these expenses will be incurred in 2004.

Project Progress Summary:

The project is under review for the best technology and lowest price compliance option, for installation in late 2003.

Project Projections:

Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $1,469,791.

Project Title: Clean Closure Equivalency Demonstration (CCED) – 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.

(January 1, 2003 to December 31, 2003)
Project Accomplishments:

No additional wells were installed and the activities are complete.

(January 1, 2003 to December 31, 2003)
Project Fiscal Expenditures:

Project expenditures are estimated to be $6,132, a 0% variance from original projections.

Project Progress Summary:

In September 1995, FPL discontinued CCED activities based on the FDEP's final decision to approve FPL's request for facility status change to generator. The approval was based on FDEP's previous acceptance of FPL's 40 CFR 264 clean closures, which were completed in 1988. Prior to September 1995, monitoring wells were completed at eight of the plants.

Project Projections:

Estimated project fiscal expenditures for the period January 2004 through December 2004 are expected to be $5,795.

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 and this job is final. The installation of the double bottom in 902 has started and is progressing on schedule.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
The variance of $126,865 or 7.8% lower than projected is due to delays in the installation of double bottoms in two tanks at the Port Everglades Plant. The delays were due to an increase in the time needed to complete the clean out of the tanks and the welding of side plates. Additionally, the installation of a tank liner at the Riviera Plant that was slated for this year has been deferred to 2004.

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. 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.

Project Projections:

Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $1,621,408.

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, 2003 - December 31, 2003)
The piping relocation on Unit 1 was completed in May 1993. Approximately 200 feet of small bore pipe was installed above ground. The Unit 2 piping relocation project was cancelled after a system review. The analysis identified the turbine lube oil piping system as piping associated with a flow through process storage tank system, rendering it exempt from Chapter 17-762 F.A.C. requirements.

Project Fiscal Expenditures:
(January 1, 2003 - December 31, 2003)
Project expenditures are estimated to be $3,391, or a 0% variance.

Project Progress Summary:

This project is complete.

Project Projections:

Estimated project fiscal expenditures (depreciation and return) for the period of January 2004 through December 2004 are expected to be $3,189.

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, 2003 to December 31, 2003)
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, 2003 to December 31, 2003)
The variance of $32,072 or 19.1% lower than projected is due to Coast Guard Rule OPA-90, part of the Oil Pollution Act, which has been put on hold until further review by the Coast Guard. This rule would have required a 25% increase in oil spill equipment in 2003. The estimated cost of the new equipment is $300,000.

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 expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $141,899.

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, 2003 - December 31, 2003)
The rerouting of the storm water runoff was completed in April 1994.

Project Fiscal Expenditures:
(January 1, 2003 - December 31, 2003)
Project expenditures are estimated to be $11,898 or a 0% variance.

Project Progress Summary:

The rerouting of the storm water runoff project is complete.

Project Projections:

Estimated project fiscal expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $11,388.

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, 2003 - December 31, 2003)
The discharge pipeline was placed in-service in February 1994.

Project Fiscal Expenditures:
(January 1, 2003 - December 31, 2003)
Project expenditures are estimated to be $90,844 or a 0% variance.

Project Progress Summary:

Installation of the discharge pipeline is complete, and it was placed in-service in February 1994.

Project Projections:

Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $86,384.

Project Title: Disposal of Noncontainerized 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 dewatered using a plate frame press to dispose in Class I landfill.

Project Accomplishments:
(January 1, 2003 - December 31, 2003)
The Plate and Frame Press was purchased and outfitted with the associated support equipment, pumps and hardware. The frame press was then placed into service in January 1997.

Project Fiscal Expenditures:
(January 1, 2003 - December 31, 2003)
Project expenditures are estimated to be $50,581 or a 0% variance.

Project Progress Summary:

This project is complete.

Project Projections:

Estimated project fiscal expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $27,470.

Project Title: Wastewater/Stormwater Discharge Elimination Project - Capital
Project 20b
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 2003 - December 2003)
The project at Port Everglades is on hold at this time pending a meeting in September to discuss the ESP project which, is going to affect the water/wastewater situation as a whole for Port Everglades. Martin is installing some upgrades for the boiler blowdown system. Cape Canaveral has deferred their project until 2004 due to timing of outages not allowing a window to do the work scheduled.

Project Fiscal Expenditures:

(January 2003 - December 2003)
Project expenditures are estimated to be $8,843 or 4.3% higher than originally projected. No significant variance is anticipated.

Project Progress Summary:

Developments since our last filing that have resulted in an elongation in the timeframe required to complete the Wastewater/Stormwater Minimization and Reuse Project. During detailed engineering and design, industry research revealed that there is limited information regarding the minimum quality of reuse water needed so as not to adversely affect the performance and/or reliability of the power generating equipment. Because of these limitations and unknowns, FPL feels it would be prudent to construct reuse systems on a limited basis and monitor the effects of the reuse water on plant equipment. It is expected that the trial implementation would need to operate for at least two (2) years before accurate conclusions could be drawn regarding acceptable reuse water quality. Accordingly, the majority of the expenditures for field-erected storage tanks and reuse pump & piping systems have been pushed beyond the year 2001.

FPL will continue to work with the FDEP to evaluate the compliance risk associated with its wastewater systems and effect additional future upgrades as necessary.

Project Projections:

Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $276,043.

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, 2003 to December 31, 2003)
The Turtle Net Project has been fully completed in November 2002.

Project Fiscal Expenditures:

(January 1, 2003 – December 31, 2003)
The variance of $16,927, or 24.3% higher than projected is primarily due to additional dredging costs. More dredging was required to expose the existing anchor blocks located at the canal bottom and the additional anchoring system was more difficult to install than originally anticipated and, therefore, required more work than expected.

Project Progress Summary:

Complete

Project Projections: Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $82,851.

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, 2003 to December 31, 2003)
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, 2003 to December 31, 2003)
The variance of $54,952 or 83.2% lower than projected is due to delays in vendor selection, which delayed the installation of positive displacement meters on the 30-inch pipeline at the Martin Plant. These installations have been deferred to 2004.

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 at FPL's Martin Plant and this should begin in January 2004.

Project Projections:

Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $101,215 of capital.

Project Title: SPCC (spill prevention, control, and countermeasures) – Capital
Project No.23
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, 2003 to December 31, 2003)
Power Systems has identified 500+ locations (substations and service centers) that will require some form of containment. An Environmental Consulting firm has been hired to design and oversee the construction of the containment, and the competitive bidding process was used to select a vendor to install the containment. Power Generation is moving toward construction starting in September. The work scope is developed and bids have been solicited. Modification work will commence in the near future. The written plan is in the process of being modified as well.

Project Fiscal Expenditures:
(January 1, 2003 to December 31, 2003)
The variance is estimated to be $81,666 or 33.8% lower than projected, and is primarily due to a change in the implementation date of the SPCC plans from August 2003 to February 2005.

Project Progress Summary:
As of December 31, 2003, containment will be installed at 144 locations.

Project Projections:
Estimated project expenditures (depreciation and return) for the period January 2004 through December 2004 are expected to be $1,343,066.

Project Title: Reburn NOx Control Technology at Manatee Plant – 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, 2003 to December 31, 2003)
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 in contracted in-house Reburn related modeling studies.

Project Fiscal Expenditures:
(January 1, 2003 to December 31, 2003)
None

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 (return on CWIP) for the period January 2004 through December 2004 are expected to be $306,662.

Project Title: Port 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, 2003 to December 31, 2003)
Anticipate November 2003 approval by the Florida Public Service Commission to proceed with Electrostatic Precipitator project as an ECRC project. The milestone schedule has been developed to support the installation of the electrostatic precipitators during planned unit outages.

Project Fiscal Expenditures:

(January 1, 2003 to December 31, 2003)
Project expenditures are projected to be $968,141, which will occur in the fourth quarter of 2003.

Project Progress Summary:

(January 2003 - December 2003)
The contract for the owner's engineer will be issued in September 2003 with the issuance of the Electrostatic precipitator specification planned for November 2003.

Project Projections:

Estimated project expenditures (return on CWIP) for the period January 2004 through December 2004 are expected to be $1,239,748.

Form 42-6P

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % By Rate Class
January 2004 to December 2004

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	62.965%	58.416%	53,694,499,279	9,734,788	10,492,790	1.09449148	1.07375594	57,654,787,546	10,654,643	11,484,269	53.28639%	58.10925%	58.02557%
GS1	64.280%	56.924%	6,085,869,172	1,080,793	1,220,452	1.09449148	1.07375594	6,534,738,174	1,182,919	1,335,774	6.03961%	6.45151%	6.74915%
GSD1	74.244%	67.961%	22,784,873,809	3,503,331	3,827,236	1.09438581	1.07367680	24,463,590,399	3,833,996	4,188,473	22.61003%	20.91019%	21.16273%
OS2	63.104%	18.904%	22,034,093	3,986	13,306	1.05884095	1.04655264	23,059,838	4,221	14,089	0.02131%	0.02302%	0.07119%
GSLD1/CS1	79.544%	72.594%	10,444,350,417	1,498,890	1,642,391	1.09287381	1.07253706	11,201,952,890	1,638,098	1,794,926	10.35320%	8.93401%	9.06907%
GSLD2/CS2	83.996%	77.485%	1,721,709,924	233,990	253,653	1.08506569	1.06615414	1,835,608,163	253,895	275,230	1.69653%	1.38472%	1.39063%
GSLD3/CS3	84.848%	0.000%	180,075,156	24,227	0	1.02896017	1.02363751	184,331,684	24,929	0	0.17037%	0.13596%	0.00000%
SST1T	107.912%	0.000%	146,444,940	15,492	0	1.02896017	1.02363751	149,906,534	15,941	0	0.13855%	0.08694%	0.00000%
SST1D	77.366%	64.707%	58,882,752	8,688	10,388	1.06491778	1.05342951	62,028,828	9,252	11,062	0.05733%	0.05046%	0.05589%
CILCD/CILCG	90.386%	83.265%	3,462,136,755	437,259	474,657	1.08267759	1.06493286	3,686,943,196	473,411	513,900	3.40759%	2.58193%	2.59654%
CILCT	96.508%	0.000%	1,591,014,236	188,194	0	1.02896017	1.02363751	1,628,621,851	193,644	0	1.50522%	1.05611%	0.00000%
MET	65.506%	56.001%	93,722,226	16,333	19,105	1.05884095	1.04655264	98,085,243	17,294	20,229	0.09065%	0.09432%	0.10221%
OL1/SL1/PL1	290.896%	47.757%	551,019,353	21,623	131,713	1.09449148	1.07375594	591,660,303	23,666	144,159	0.54683%	0.12907%	0.72838%
SL2	99.875%	99.875%	76,974,890	8,798	8,798	1.09449148	1.07375594	82,652,246	9,629	9,629	0.07639%	0.05252%	0.04865%
TOTAL			100,913,607,000	16,776,392	18,094,489			108,197,966,894	18,335,538	19,791,740	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 2004 through December 2004
(4) Calculated: (Col 3)/(8,760 * Col 1)
(5) Calculated: (Col 3)/8,760 * Col 2)
(6) Based on 2002 demand losses
(7) Based on 2002 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 2004 to December 2004

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	53.28639%	58.10925%	58.02557%	$3,763,502	$2,944,754	$473,119	$7,181,375	53,694,499,279	0.00013
GS1	6.03961%	6.45151%	6.74915%	$426,565	$326,938	$55,030	$808,533	6,085,869,172	0.00013
GSD1	22.61003%	20.91019%	21.16273%	$1,596,897	$1,059,648	$172,553	$2,829,098	22,784,873,809	0.00012
OS2	0.02131%	0.02302%	0.07119%	$1,505	$1,167	$580	$3,252	22,034,093	0.00015
GSLD1/CS1	10.35320%	8.93401%	9.06907%	$731,224	$452,741	$73,946	$1,257,911	10,444,350,417	0.00012
GSLD2/CS2	1.69653%	1.38472%	1.39063%	$119,822	$70,172	$11,339	$201,333	1,721,709,924	0.00012
GSLD3/CS3	0.17037%	0.13596%	0.00000%	$12,033	$6,890	$0	$18,923	180,075,156	0.00011
SST1T	0.13855%	0.08694%	0.00000%	$9,785	$4,406	$0	$14,191	146,444,940	0.00010
SST1D	0.05733%	0.05046%	0.05589%	$4,049	$2,557	$456	$7,062	58,882,752	0.00012
CILC D/CILC G	3.40759%	2.58193%	2.59654%	$240,671	$130,842	$21,171	$392,684	3,462,136,755	0.00011
CILC T	1.50522%	1.05611%	0.00000%	$106,311	$53,520	$0	$159,831	1,591,014,236	0.00010
MET	0.09065%	0.09432%	0.10221%	$6,403	$4,780	$833	$12,016	93,722,226	0.00013
OL1/SL1/PL1	0.54683%	0.12907%	0.72838%	$38,622	$6,541	$5,939	$51,102	551,019,353	0.00009
SL2	0.07639%	0.05252%	0.04865%	$5,395	$2,661	$397	$8,453	76,974,890	0.00011
TOTAL				$7,062,783	$5,067,617	$815,363	$12,945,763	100,913,607,000	0.00013

Notes: 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 2004 through December 2004
(9) Col 7 / Col 8 x 100

Comp. Exh. 2

FLORIDA ADMINISTRATIVE CODE – TITLE 62

DEPARTMENT OF ENVIRONMENTAL PROTECTION

CHAPTER 62-761.500

RRL-1
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT _____
PAGES 1-17

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030007-EI EXHIBIT NO. Comp. Ex. 2
COMPANY/ FPL
WITNESS: R. R. LaBauve RRL-1 thru RRL-7
DATE: 11-12-03

3. A spill or overfill event of a regulated substance to soil or another pervious surface, equal to or exceeding 25 gallons, unless the regulated substance has a more stringent reporting requirement specified in C.F.R. Title 40, Part 302;

4 Results of analytical or field tests of soil indicating the presence of contamination by:

a. A hazardous substance from a UST system;

b. A regulated substance, other than petroleum products;

c. Petroleum products' chemicals of concern that exceed the lower of direct exposure I and leachability Table V cleanup target levels specified in Table IV in Chapter 62-770, F.A.C., unless due to a spill or overfill event in a quantity less than that described in subparagraph 3. above; or

5. Soils stained by regulated substances that are observed during a closure assessment performed in accordance with Rule 62-761.800(4), F.A.C.

(b) Copies of analytical or field test results that confirm a discharge shall be submitted to the County with Discharge Report Form 62-761.900(1).

(c) A request for a retraction of a submitted Discharge Report Form may be submitted to the County or the Department if evidence is presented that a discharge did not occur at the facility.

(d) A Discharge Report Form 62-761.900(1) does not need to be submitted for previously reported discharges.

Specific Authority 376.303, FS.
Law Implemented 376.303, FS.
History -- New 12-10-90, Formerly 17-761.450, Amended 9-30-96, 7-13-98.

62-761.460 Reporting. (Repealed)

Specific Authority 376.303, FS.
Law Implemented 376.303, FS.
History -- New 12-10-90, Formerly 17-761.450, Repealed 9-30-96.

62-761.480 Financial Responsibility. (Repealed)

Specific Authority 376.303, 376.309, FS.
Law Implemented 376.303, 376.309, FS.
History -- New 12-10-90, Formerly 17-761.480, Repealed 9-30-96.

62-761.500 *Performance Standards for Category-C Storage Tank Systems.*

(1) General performance standards. AST and UST Category-C systems shall be constructed and installed in accordance with the requirements of this section. AST and UST Category-C systems shall be made of, or internally lined with, materials that are compatible with the regulated substance stored in the system. The following requirements are applicable to both UST and AST systems:

(a) Siting. Persons are advised that, pursuant to Rule 62-521.400(1)(l)-(n) and (2), F.A.C., no storage tank shall be installed within 500 feet of any existing community water supply system or any existing non-transient non-community water supply system. No Category-C system (AST or UST) shall be installed within 100 feet of any other existing potable water supply well. These prohibitions shall not apply to the replacement of an existing storage tank system within the same excavation or dike field area, or the addition of new storage systems meeting the standards for Category-C systems at an existing facility.

(b) Exterior coatings. Exterior portions of aboveground tanks and aboveground integral piping, excluding double-walled systems, shall be coated or otherwise protected from external corrosion. The coating shall be designed and applied to resist corrosion, deterioration, and degradation of the exterior wall. SSPC-PA 1, Paint Application Specification No. 1 may be used to protect storage tank systems from external corrosion.

(c) Spill containment. USTs and shop-fabricated ASTs shall be installed with a spill containment system at each tank fill connection. The spill containment system shall be a fixed component that is designed to prevent a discharge of regulated substances when the transfer hose or pipe is detached from the tank fill pipe. The spill containment system shall meet the requirements of Rule 62-761.500(1)(e), F.A.C.

(d) Dispensing systems.

1. The dispensing system used for transferring fuels from storage tanks shall be installed and maintained in accordance with the provisions of NFPA 30 and Chapters 2, 4 and 9 of NFPA 30A.

2. Dispensers shall be designed, constructed, and maintained to provide access for examination and removal of collected product and accumulated water from dispenser liners.

(e) Secondary containment.

1. The materials used for secondary containment shall be:

a. Impervious to the regulated substance and able to withstand deterioration from external environmental conditions;

b. Non-corrosive or of corrosion-protected materials;

c. Capable of containing regulated substances for at least 30 days; and

d. Of sufficient thickness and strength to withstand hydrostatic forces at maximum capacity to prevent a discharge during its operating life.

2. Liners, unless previously approved by the Department, shall be approved by the Department in accordance with Rule 62-761.850(2), F.A.C. Liners shall not be constructed or consist of naturally occurring in-situ soils.

3. Secondary containment constructed of concrete shall be:

a. Designed and constructed in accordance with ACI 350R-89 and ACI 224R-89; or

b. Lined on the visible interior surfaces of the dike field area in accordance with NACE International Standard RP 0892-92, or SSPC Publication 97-04, Design,

Installation, and Maintenance of Coating Systems for Concrete Used in Secondary Containment; or

c. Designed, evaluated, and certified by a professional engineer registered in the State of Florida that the concrete secondary containment system meets the General Construction Requirements specified in Rule 62-761.500(1)(e)1., F.A.C.

4. For cathodically protected tanks and integral piping, secondary containment systems shall not interfere with the operation of the cathodic protection system.

5. Storage tank system equipment with closed interstitial spaces, such as double-walled USTs, double-bottomed ASTs, and double-walled integral piping in contact with the soil that is connected to ASTs or USTs, shall be designed, constructed and installed to allow for the detection of a breach of integrity in the inner or outer wall by the monitoring of the interstitial space in accordance with Rule 62-761.640(3)(a), F.A.C. A breach of integrity test shall be performed before the storage tank system is put into service.

6. Secondary containment systems shall be designed and installed to direct any release to a monitoring point or points.

7. *Airport and seaport hydrant pits.* Underground hydrant pits shall be installed with a spill catchment basin, secondary containment, or other spill prevention equipment to prevent the discharge of pollutants during fueling of aircraft, vessels, or at any other time the hydrant system is in use. Any such equipment shall be sealed to and around the hydrant piping *with an impervious, compatible material.*

8. Field-fabricated dispenser liners and piping sumps installed before July 13, 1998 do not have to be approved in accordance with Rule 62-761.850, F.A.C.

(f) Cathodic protection.

1. Test stations. Cathodic protection systems shall be designed, constructed, and installed with at least one test station or method of monitoring to allow for a determination of current operating status. Cathodic protection test stations shall provide direct access to the soil electrolyte in close proximity to each cathodically protected structure for placement of reference electrodes, and monitoring wires that connect directly to cathodically protected structures. Facilities where direct access to soil in close proximity to cathodically protected structures is present, and where electrical connections to cathodically protected structures can be conveniently accomplished, need not have separate dedicated cathodic protection test stations.

2. The cathodic protection system shall be operated and maintained in accordance with Rule 62-761.700(1)(b), F.A.C.

3. Any field-installed cathodic protection system shall be designed by a Corrosion Professional.

(g) Relocation of USTs. Tanks that have been removed and that are to be reinstalled at a different location shall:

1. Be recertified that all original warranties are confirmed by the original manufacturer or the manufacturer's successor, and be reinstalled in accordance with the standards in Rule 62-761.500, F.A.C., that were in effect on July 13, 1998; or

2. Be recertified by a professional engineer registered in the State of Florida that the UST meets all applicable standards of Rule 62-761.500, F.A.C. in effect on July 13, 1998; and

3. Proof of recertification shall be provided to the Department and County prior to the completion of installation. The provisions of Rule 62-761.850(2), F.A.C., do not apply to the requirements of this subparagraph.

(h) Relocation of ASTs. Tanks that have been removed and that are to be reinstalled at a different location shall:

1. For field-erected tanks, comply with API Standard 653; or

2. For shop-fabricated tanks, be reinstalled in accordance with manufacturer's specifications, if applicable, and with the standards in Rule 62-761.500, F.A.C., that were in effect on July 13, 1998.

(i) Reuse of storage tanks. Unless it is recertified for use by a professional engineer registered in the State of Florida, or is recertified by the manufacturer, and is brought into service in accordance with Rule 62-761.500, F.A.C.:

1. A UST can not be used or reused as an AST for the storage of regulated substances; and

2. An AST can not be used or reused as a UST for the storage of regulated substances.

(2) Underground storage tank systems.

(a) Installation.

1. All components of a storage tank system shall be installed in accordance with the manufacturer's instructions.

2. All storage tank systems shall be installed according to the applicable provisions of NFPA 30 and 30A, PEI/RP100-97, and API RP 1615.

3. A Certified Contractor shall perform the installation of storage tank systems containing pollutants, including tanks, integral piping (excluding drop tubes), overfill protection and spill containment equipment, internal release detection equipment, cathodic protection systems, secondary containment systems, and dispensing systems, if the installation of the storage tank system component disturbs the backfill, or where the integral piping is connected or disconnected during installation.

4. A tightness test shall be performed on the tank and integral piping before any storage tank system is placed into service unless the system's equipment approval specifies otherwise.

(b) Tank construction standards.

1. Fiberglass reinforced plastic tanks shall be constructed in accordance with UL 1316 and ASTM Standard D4021-86, or certified by a nationally recognized laboratory that these standards are met.

2. Cathodically protected steel tanks shall be:

a. Constructed in accordance with UL 58 and UL 1746, or as applicable;

b. Constructed in accordance with STI #STI-P_3® Specification and Manual for External Corrosion Protection of Underground Steel Storage Tanks; or

c. Certified by a Nationally Recognized Laboratory that these standards are met, and constructed and designed by a corrosion professional in accordance with NACE International Standard RP0285-95 for any field-installed cathodic protection system.

3. Steel tanks coated with a fiberglass reinforced plastic composite shall be constructed in accordance with UL-58 and either UL 1746, STI ACT 100® (F894), or certified by a nationally recognized laboratory that one of these standards is met.

4. Storage tanks constructed of any other material, design, or corrosion protection shall be approved by the Department in accordance with Rule 62-761.850(2), F.A.C.

5. Any new tank manufactured with previously used or remanufactured components shall be certified before being installed as meeting the applicable standards by Underwriters Laboratory, by a comparable certified product testing laboratory, or by a professional engineer registered in the State of Florida.

6. Tanks shall be constructed or installed to provide for interstitial monitoring.

(c) Secondary containment. All tanks installed or constructed at a facility after July 13, 1998 shall have secondary containment.

(d) Overfill protection.

1. At a minimum, fillbox covers shall be marked in accordance with API RP 1637, or with an equivalent method approved by the Department in accordance with Rule 62-761.850(2), F.A.C.

2. USTs shall be equipped with a system that either:

a. Automatically shuts off flow to the tank when the tank is no more than 95% full;

b. Restricts flow to the tank when the tank is no more than 90% full;

c. Alerts the transfer operator when the tank is no more than 90% full by triggering a high level alarm;

d. Alerts the transfer operator with a high level alarm set at 400 gallons below tank top, but no less than one minute before overfilling; or

e. Automatically shuts off flow into the tank so that none of the fittings located on top of the tank are exposed to product due to overfilling.

(e) Dispenser liners.

1. Storage tank systems installed or replaced after July 13, 1998 shall be installed with liners meeting the performance standards of Rule 62-761.500(1)(e), F.A.C., beneath the union of the piping and the dispenser.

2. Hydrostatic tests shall be performed for all dispenser liners before placing the system into service. The duration of the tests shall be at least:

a. Twenty-four hours for field-fabricated dispenser liners; or

b. Three hours for factory-made dispenser liners.

3. Dispenser liners shall be installed to allow for interstitial monitoring in accordance with Rule 62-761.640(3)(a), F.A.C.

(f) Piping sumps.

1. Piping sumps installed after July 13, 1998 shall meet the performance standards of Rule 62-761.500(1)(e), F.A.C. The sumps shall be designed, constructed, and installed to minimize water entering the sump.

2. Hydrostatic tests shall be performed for all piping sumps before placing the system into service. The duration of the tests shall be at least:

a. Twenty-four hours for field-fabricated piping sumps; or

b. Three hours for factory-made piping sumps.

3. Piping sumps shall be installed to allow for interstitial monitoring in accordance with Rule 62-761.640(3)(a), F.A.C.

(3) Aboveground storage tank systems.

(a) Installation.

1. All components of a storage tank system shall be installed in accordance with the manufacturer's instructions.

2. Storage tank systems shall be installed according to the applicable provisions of NFPA 30, NFPA 30A and PEI/RP200-96.

(b) Tank construction standards.

1. Shop-fabricated tanks shall be constructed in accordance with one of the following:

a. UL 142;

b. API Standard 620;

c. API Specification 12B;

d. API Specification 12F;

e. API Specification 12P;

f. STI F911-93;

g. STI F921®;

h. ASME B96.1; or

i. UL 2085.

2. Field-erected tanks shall be constructed in accordance with one of the following:

a. ASME B96.1;

b. API Standard 620;

c. API Standard 650;

d. API Specification 12B; or

e. API Specification 12D.

3. Field-erected tanks shall have an inspection and testing frequency established in accordance with API Standard 653 and maintained for the life of the tank.

4. Steel tanks in contact with soil shall have a cathodic protection system meeting the following requirements:

a. The cathodic protection system shall be designed, constructed, and installed in accordance with API RP 651 and NACE International Standard RP-0193-93;

b. A field-installed cathodic protection system shall be designed by a Corrosion Professional;

c. The cathodic protection system shall be designed and installed with at least one test station in accordance with Rule 62-761.500(2)(b)2.b., F.A.C., or a method of monitoring to allow for a determination of current operating status; and

d. The cathodic protection system shall be operated and maintained in accordance with Rule 62-761.700(1)(b), F.A.C.

5. Tanks constructed of any other material, design, or corrosion protection shall be approved by the Department in accordance with Rule 62-761.850(2), F.A.C.

(c) Secondary containment.

1. All tanks installed or constructed at a facility after July 13, 1998 shall have secondary containment beneath the tank and within the dike field area, except for the following:

a. Tanks containing high viscosity regulated substances are exempt from the requirements for secondary containment. However, used or waste oil tanks, regardless of viscosity, shall have secondary containment beneath the tank and within the dike field area.

b. Double-walled shop-fabricated tanks approved in accordance with Rule 62-761.850(2), F.A.C., do not have to be installed in a dike field area.

c. Shop-fabricated tanks containing petroleum contact water pursuant to Chapter 62-740, F.A.C., that are subject to this chapter, elevated above and not in contact with the soil, and that have an impervious surface directly beneath the area of the tank.

d. Field-erected tanks used for the temporary storage of petroleum contact water pursuant to Chapter 62-740, F.A.C., that are subject to this chapter, and that have passed an internal inspection for structural integrity in accordance with API Standard 653.

e. AST Category-C field-erected tanks constructed within a dike field area with AST Category-A field-erected tanks shall have secondary containment beneath the tank, but shall not be required to have secondary containment within the dike field area until December 31, 1999.

2. Release prevention barriers such as double-bottoms, liners, or other undertank secondary containment systems for field-erected tanks shall be designed and constructed in accordance with API Standard 650.

3. Dike field areas with secondary containment shall:

a. Conform to the requirements of NFPA 30, Chapter 2-3;

b. Contain a minimum of 110% of the maximum capacity of the tank or of the largest single-walled tank within the dike field area. Capacity calculations shall include the volume occupied above the area of the "footprint" of the tank bottom or the largest tank within the dike field area;

c. If not roofed or otherwise protected from the accumulation of rainfall, be constructed with a manually controlled pump or siphon, or a gravity drain pipe which has a manually controlled valve to remove accumulated liquids. Gravity drain pipes shall be designed and constructed to prevent a discharge in the event of fire;

d. Have all integral piping and other penetrations that pass through the secondary containment of dike field areas sealed around the outside of the penetration with an impervious compatible material to prevent the discharge of pollutants; and

e. If constructed of steel, be tested in accordance with UL 142.

(d) Overfill protection.

1. No transfer of regulated substances shall be made unless the volume available in the tank is greater than the volume of regulated substances to be transferred. The transfer shall be repeatedly monitored to prevent overfilling.

2. Overfill protection shall be performed in accordance with API RP 2350.

3. At a minimum, fillbox covers shall be marked in accordance with API RP 1637, or an equivalent method approved by the Department in accordance with Rule 62-761.850(2), F.A.C.

4. All tanks shall be equipped with at least one of the following:

a. A gauge or other measuring device that accurately shows the level of pollutant in the tank and that is visible to the person who is monitoring the filling;

b. A high level warning alarm;

c. A high level liquid flow cutoff controller;

d. An impervious dike field area; or

e. Another device approved in accordance with Rule 62-761.850(2), F.A.C.

5. Calibrated stick measurements of the level of pollutants in the tank shall only be used for tanks with a capacity of 15,000 gallons or less that are not loaded with high-volume pressurized nozzles. Such tanks shall not be loaded beyond 95% capacity.

(e) Dispenser liners.

1. Dispensers connected to AST systems that are installed or replaced after July 13, 1998 shall be installed with liners meeting the performance standards of Rule 62-761.500(1)(e), F.A.C., beneath the union of the piping and the dispenser. Dispensers mounted directly upon a tank are exempt from this requirement.

2. Hydrostatic tests shall be performed for all dispenser liners before placing the system into service. The duration of the tests shall be at least:

a. Twenty-four hours for field-fabricated dispenser liners; or

b. Three hours for factory-made dispenser liners.

3. Dispenser liners shall be installed to allow for interstitial monitoring in accordance with Rule 62-761.640(3)(a), F.A.C.

(f) Piping sumps.

1. Piping sumps installed after July 13, 1998 shall meet the performance standards of Rule 62-761.500(1)(e), F.A.C. The sumps shall be designed, constructed, and installed to minimize water entering the sump.

2. Hydrostatic tests shall be performed for all piping sumps before placing the system into service. The duration of the tests shall be at least:

a. Twenty-four hours for field-fabricated piping sumps; or

b. Three hours for factory-made piping sumps.

3. Piping sumps shall be installed to allow for interstitial monitoring in accordance with Rule 62-761.640(3)(a), F.A.C.

(4) Integral piping for aboveground and underground storage tank systems.

(a) Installation.

1. All integral piping shall be installed in accordance with the manufacturer's instructions, if applicable.

2. All integral piping shall be installed according to the applicable provisions of NFPA 30, NFPA 30A, and ASME B31.4.

3. A tightness test shall be performed on underground small diameter piping associated with ASTs before any new underground piping system is placed into service. A pressure test shall be performed for underground bulk product piping before the piping system is placed into service. Tightness tests for underground small diameter piping connected to USTs are subject to Rule 62-761.500(2)(a)4., F.A.C.

4. All piping that is not in contact with the soil, installed after July 13, 1998, shall meet the construction standards in Rule 62-761.500(4)(a)-(d), F.A.C.

(b) *Integral piping construction standards.*

1. Fiberglass reinforced plastic piping or other non-metallic piping installed at a facility shall be listed with UL 971, UL 567, certified by a Nationally Recognized Laboratory that these standards are met, or approved in accordance with Rule 62-761.500(4)(b)3, F.A.C.

2. Coated steel piping shall be constructed in accordance with ASME B31.4. Integral piping in contact with the soil shall be cathodically protected in accordance with API RP 1632, NACE International RP-0169-96, and STI R892-96.

3. Integral piping constructed of other materials, design, or corrosion protection shall be approved by the Department in accordance with Rule 62-761.850(2), F.A.C.

(c) Small diameter piping.

1. Pressurized small diameter piping systems connected to dispensers shall be installed with shear valves or emergency shutoff valves in accordance with NFPA 30A, Section 4-3.6, if applicable. These valves shall be designed to close automatically if a dispenser is dislodged from the integral piping. The valves shall be rigidly anchored independently of the dispenser. For underground small diameter piping, the valves shall be checked at the time of installation by a certified contractor to confirm that the automatic closing function of the valve operates properly and that the valve is properly anchored.

2. Gravity-fed small diameter integral piping systems must be installed with an isolation valve at the point of connection to the storage tank to prevent the discharge of regulated substances in the case of piping failure. The valve shall meet the standards of NFPA 30A, Section 2-1.7.

3. Swing-joints shall not be installed.

(d) Bulk product piping. Bulk product piping shall be constructed and installed in accordance with NFPA 30, and ASME B31.4.

(e) Secondary containment.

1. Small diameter integral piping that is in contact with the soil or that transports regulated substances over surface waters of the state shall have secondary containment.

2. Bulk product piping that is in contact with the soil shall have secondary containment.

3. Remote fill piping that is in contact with the soil shall have secondary containment.

4. The following integral piping systems are exempt from the requirements for secondary containment:

a. Integral piping that is in contact with the soil, and that is connected to storage tanks containing high viscosity regulated substances; and

b. Vertical fill pipes equipped with a drop tube.

Specific Authority 376.303 FS.
Law Implemented 376.303 FS.
History--New 12-10-90, Amended 5-4-92, Formerly 17-761.500, Amended 9-30-96, 7-13-98.

62-761.510 Performance Standards for Category-A and Category-B Storage Tank Systems.

(1) General. This section provides deadlines for Category-A and Category-B storage tank systems to meet the standards for Category-C storage tank systems in accordance with Rule 62-761.500, F.A.C.

(a) Installation:

1. Installation shall be completed by the deadlines specified in Table UST and Table AST. However, if installation or upgrade activities are initiated before the deadlines, work can continue after the deadlines, provided that all work is completed within 90 days of:

a. Contract execution; or

b. Receipt of construction approval or permits.

2. Installation is considered to have begun if:

a. All federal, state, and local approvals or permits have been obtained or applied for to begin physical construction for installation of the system; or

b. Contractual obligations have been made for installation of the system which cannot be canceled or modified without substantial economic loss, provided that such obligations are pursued diligently in good faith to achieve the requirements of this rule.

(b) By December 31, 1998:

1. All pressurized small diameter piping systems connected to dispensers shall have shear valves or emergency shutoff valves installed in accordance with Rule 62-761.500(4)(c), F.A.C.

2. Cathodic protection test stations shall be installed in accordance with Rule 62-761.500(1)(f)1. and (2)(b)2. F.A.C., for cathodically protected UST or AST systems without test stations.

3. Fillboxes shall be color coded in accordance with Rule 62-761.500(2)(d)1., F.A.C.

4. ASTs that have been reinstalled as USTs, and USTs that have been reinstalled as ASTs, shall meet the requirements of Rule 62-761.500, F.A.C.

(c) After July 13, 1998, a closure assessment shall be performed in accordance with Rule 62-761.800(4), F.A.C., before the installation of dispenser liners, piping sumps, or secondary containment of tanks and integral piping.

(d) Valves meeting the requirements of Section 2-1.7 of NFPA 30A, shall be installed by January 13, 1999 on any storage tank system located at an elevation that produces a gravity head on the dispenser or on small diameter piping.

(e) Small diameter piping transporting regulated substances over surface waters of the state shall have secondary containment by December 31, 2004.

(2) Underground storage tank systems.

(a) UST Category-A single-walled tanks or underground single-walled piping shall be considered to be protected from corrosion if the tank or piping was constructed with corrosion resistant materials, initially installed with cathodic protection, or had cathodic protection or internal lining installed before June 30, 1992.

(b) UST Category-B systems.

1. All tanks containing pollutants, installed or constructed at a facility after June 30, 1992, shall have secondary containment.

2. All tanks containing hazardous substances, installed or constructed at a facility after January 1, 1991, shall have secondary containment.

(c) Small diameter integral piping in contact with the soil that is connected to UST systems shall have secondary containment if installed after December 10, 1990.

(d) By December 31 of the appropriate year shown in Table UST below, all storage tank systems shall meet the performance standards of Rule 62-761.500, F.A.C., or be permanently closed in accordance with Rule 62-761.800(3), F.A.C.

TABLE UST

Year Tank or Integral Piping Installed	1989	1992	1995	1998	2004	2009
+Before 1970	O	B		ACFL	D	E
+1970 - 1975		SBL		ACF	D	E
+I976 - 1980		B	SL	ACF	D	E
+1981 - 09/01/84		B		ACFL	D	E
+09/02/84 – 06/30/92		B		ACFL	D	E
+Other*		B		ACFL	D	E

Key to Table UST

* = All systems with a capacity between 110 gallons and 550 gallons, all marine fueling facilities as defined in Section 376.031, F.S., and those systems of greater than 550 gallon capacity that use less than 1,000 gallons per month or 10,000 gallons per year.

A =

(1) Small diameter piping that was protected from corrosion by June 30, 1992, shall have:

(a) For pressurized piping, line leak detectors with automatic shutoff, or flow restriction in accordance with Rule 62-761.640(3)(d), F.A.C.; or

(b) For suction integral piping:

1. Secondary containment in accordance with Rule 62-761.500(1)(e), F.A.C.;

2. A single check valve installed in accordance with Rule 62-761.610(4)(a)3., F.A.C.;

3. An annual line tightness test in accordance with Rule 62-761.610(4)(a)1., F.A.C.; or

4. External monthly monitoring or release detection in accordance with Rule 62-761.610(4)(a)1.b., F.A.C.

(2) Bulk product piping in contact with soil shall be upgraded with secondary containment unless the piping is:

(a) Constructed of corrosion resistant materials or upgraded with cathodic protection; and

(b) Tested on an annual basis in accordance with API RP 1110, ASME B31.4, or an equivalent method approved by the Department in accordance with Rule 62-761.850, F.A.C.

B = Vehicular fuel petroleum storage tank systems shall be upgraded with spill containment.

C = Secondary containment in accordance with Rule 62-761.500(1)(e), F.A.C., shall be required for the following:

(1) Concrete storage tanks;

(2) Hazardous substance storage tank systems; and

(3) For pollutant storage tank systems, the storage tank or small diameter piping not protected from corrosion by June 30, 1992.

D = (1) Secondary containment shall be installed for small diameter piping extending over surface waters.

(2) Secondary containment for remote fill-pipes associated with Category-A and Category-B systems.

E = Pollutant storage tanks and small diameter piping protected from corrosion on or before June 30, 1992, and all manifolded piping, shall be upgraded with secondary containment.

F =

(1) Storage tank systems, excluding vehicular fuel petroleum storage tank systems, shall be upgraded with spill containment, dispenser liners (as applicable), and overfill protection.

(2) Unless contained within secondary containment, swing-joints and flex-connectors that are not protected from corrosion shall be protected from corrosion. Facilities that have pressurized small diameter piping and that have not met the foregoing standard on or before July 13, 1998 shall protect the submersible turbine pump from corrosion or provide corrosion protection for the submersible turbine pump if the pump is not installed within secondary containment. Corrosion protection is not required for the submersible turbine pump riser.

L =

(1) Category-A USTs and their integral piping systems that contain vehicular fuel, and that are not protected from corrosion, shall have secondary containment, or be upgraded with secondary containment in accordance with Rule 62-761.500, F.A.C.

(2) Dispenser liners and overfill protection equipment shall be installed at UST Category-A systems containing vehicular fuel.

O = UST Category-A vehicular fuel storage tank systems subject to Chapter 17-61, F.A.C.,(1984), shall be retrofitted for corrosion protection.

S = Secondary containment for storage tanks and integral piping not protected from corrosion.

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(3) Aboveground storage tank systems.

(a) All storage tank systems with tanks having capacities greater than 550 gallons that contain vehicular fuel and that were subject to Chapter 17-61, F.A.C., shall have met the requirements of such chapter by January 1, 1990.

Effective 7-13-98

(b) AST Category-B tanks, with the exception of tanks exempt under Rule 62-761.500(3)(c)1., F.A.C., installed or constructed at a facility after March 12, 1991, shall have secondary containment for the tank.

(c) Integral piping that is in contact with the soil and that is connected to AST systems shall have secondary containment if installed after March 12, 1991. For integral piping that is exempt under Rule 62-761.500(4)(e)4., F.A.C., it is not required to install secondary containment.

(d) By January 1 of the appropriate year shown in Table AST below, unless specified otherwise, all AST Category-A and Category-B storage tank systems shall meet the following requirements or be permanently closed in accordance with Rule 62-761.800(3), F.A.C.

TABLE AST

Year Tank or Integral Piping Installed	1993	2000	2005	2010
+Before July 13, 1998	P	TVX	W	U

Key to Table AST

P = With the exception of high viscosity bulk product piping, bulk product piping in contact with soil and not in secondary containment shall be tested in accordance with API RP 1110, ASME B31.4, or an equivalent method approved by the Department in accordance with Rule 62-761.850, F.A.C. Such testing shall be performed annually thereafter.

T =

(1) With the exception of siting and material construction standards, Category-A and Category-B systems shall meet the performance standards of Rule 62-761.500, F.A.C. In addition:

(a) Storage tank system construction standards that include cathodic protection remain applicable; and

(b) Storage tanks where the entire bottom of the tank is in contact with concrete do not have to seal the concrete beneath the tank until such time that the tank bottom is replaced. However, concrete secondary containment systems designed in accordance with Rule 62-761.500(1)(e)3., F.A.C., do not have to be sealed.

(2) Category-A bulk product piping in contact with the soil shall be upgraded with secondary containment, unless:

(a) A structural evaluation is performed in accordance with API 570, as specified in "U" (2)(b), of Table AST, and results of the structural evaluation indicate that the bulk product piping has remaining useful life; or

(b) The integral piping conveys high viscosity regulated substances, that are exempt from secondary containment in accordance with Rule 62-761.500(4)(e) 4., F.A.C.; or

(c) The integral piping is protected from corrosion and is tested annually in accordance with ASME B31.4, API 1110, or an equivalent method approved by the Department in accordance with Rule 62-761.850, F.A.C. This piping shall have secondary containment by January 1, 2010, in accordance with "U" of Table AST.

(3) Initial internal and external inspections, examinations, and tests for each tank shall be performed in accordance with API Standard 653, and an appropriate reinspection interval for each tank shall be established in accordance with API Standard 653. If any deficiency is discovered during the inspections, the person performing the evaluation of the tank in accordance with API 653 must verify that the tank is ready for service before the storage tank is put back into service. This verification must be documented in the internal inspection records. Future tests for each tank shall be performed in accordance with the inspection interval established in accordance with API 653 (1996). Baseline inspections already conducted according to the API Standard 653 (1991) will be accepted.

(4) As an alternative to installing secondary containment underneath an AST Category-A or Category-B storage tank, the interior bottom of the tank and at least 18 inches up the sides may be internally lined in accordance with API RP 652. Secondary containment must nonetheless be installed in the dike field area and be continuously bonded to the perimeter of the tank foundation.

U =

(1) All internally lined single bottom storage tanks, with the exception of tanks exempt under Rule 62-761.500(3)(c)1., F.A.C., shall be upgraded with secondary containment.

(2) All AST Category-A bulk product piping in contact with the soil , except for piping exempt from secondary containment requirements under Rule 62-761.500(4)(e)4. F.A.C., shall be:

(a) Upgraded with secondary containment in accordance with Rule 62-761.500(1)(e), F.A.C.; or

(b) Instead of being upgraded with secondary containment, be evaluated for structural integrity by:

1. Establishing and maintaining the piping inspection intervals in accordance with API 570, Section 4-2, by January 1, 2000;

2. Determining the remaining life of the system in accordance with API 570, Section 5.0, by January 1, 2000. If the determination indicates that the piping:

a. Must be repaired, then the piping shall be repaired within three months of the determination in accordance with API 570 and Rule 62-761.700, F.A.C.;

b. Is leaking, then the piping must be immediately taken out of operation. If the piping cannot be repaired, it must be closed or upgraded with secondary containment within one year of the determination;

c. Is not leaking, but has corroded to a point where it no longer has structural integrity, then the piping shall be closed, or upgraded with secondary containment by January 1, 2000; or

d. Has remaining useful life, then the piping shall be closed or upgraded with secondary containment when the API 570 inspection and remaining life determination data indicates that closure or replacement is necessary.

3. Providing a certification by a professional engineer registered in the State of Florida that the evaluation meets the above criteria.

V =

(1) Secondary containment for cut and cover or concrete storage tanks.

(2) Spill containment in accordance with Rule 62-761.500(1)(c), F.A.C.

(3) Dispenser liners for shop-fabricated tanks in accordance with Rule 62-761.500(3)(e), F.A.C.

(4) Secondary containment in accordance with Rule 62-761.500(1)(e) and (3)(c), F.A.C., for dike field areas of facilities with shop-fabricated tanks having dike field area secondary containment that is constructed of concrete or installed with synthetic liners not meeting these requirements.

W =

(1) Secondary containment in accordance with Rule 62-761.500(1)(e) and (3)(c), F.A.C., for dike field areas of facilities with field-erected tanks having dike field area secondary containment that is constructed of concrete or installed with synthetic liners not meeting these requirements.

(2) Secondary containment for small diameter piping extending over surface waters.

(3) Secondary containment for small diameter petroleum contact water piping in contact with the soil.

X = Deadline to determine integrity of single wall bulk product piping with an API 570 structural integrity evaluation in accordance with the option for Category-A systems in "U" of Table AST.

Specific Authority 376.303 FS. Law Implemented 376.303-376.3072 FS. History--New 12-10-90, Amended 5-4-92, Formerly 17-761.510, Amended 9-30-96, 07-13-98.

62-761.520 Performance Standards for Other Existing Petroleum and Petroleum Product Storage Tank Systems (Non-Vehicular Fuels). (Repealed)

Specific Authority 376.303, FS.
Law Implemented 376.303, FS.
History -- New 12-10-90, Amended 5-4-92, Formerly 17-761.520, Repealed 9-30-96.

62-761.550 Performance Standards for New Hazardous Substance Storage Tank Systems. (Repealed)

Specific Authority 376.303, FS.

Effective 7-13-98

FPL'S EXISTING

UNDERGROUND STORAGE TANK SYSTEMS

RRL-2
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT _____
PAGES 1-2

Tank ID	Size (Gallons)	Contents	Description	Location	Year Installed	Removal / Replacement	Year of Removal/ Replacement
Tank 1R1	4000	Unleaded Gas	Single-walled	Turkey Point Unit 3 - Land Utilization	1988	Replace with AST	2004
Tank 2R2	4000	Vehicular Diesel	Single-walled	Turkey Point Unit 4 - Land Utilization)	1988	Replace with AST	2004
Tank # 1	1000	Vehicular Diesel	Single-walled	Area Office Broward	1989	Replace with AST	2005
Tank # 1	6000	Vehicular Diesel	Single-walled	Customer Service East Office	1989	Replace with AST	2006
Tank # 1	6000	Unleaded Gas	Single-walled	Juno Beach Office	1986	Replace with AST	2005
Tank # 7&# 8	10000	Vehicular Diesel	Single-walled	General Office	1992	Replace with AST	2005
1	1000	Vehicular Diesel	Single-walled	Ft. Lauderdale Plant	1990	Remove	2004

St. JOHN'S RIVER WATER MANAGEMENT DISTRICT

CONSUMPTIVE USE PERMIT NO. 10652

CAPE CANAVERAL PLANT

RRL-3
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT _____
PAGES 1-9

St. Johns River
Water Management District

Kirby B. Green III, Executive Director. John R. Wehle, Assistant Executive Director

Post Office Box 1429 • Palatka, FL 32178-1429 • (386)329-4500

October 9,2001

Florida Power and Light company
6000 North US Highway 1
Cocoa, FL 32927

SUBJECT: Consumptive Use Permit Number 10652
Cape Canaveral Plant

Dear Sir/Madam:

Enclosed is your permit and the forms necessary for submitting information to comply with conditions of the permit as authorized by the St. Johns River Water Management District on October 09,2001.

Permit issuance does not relieve you from the responsibility of obtaining permits from any federal, state and/or local agencies asserting concurrent jurisdiction over this work.

The enclosed permit is a legal document and should be kept with your other important records. Please read the permit and conditions carefully since the referenced conditions may require submittal of additional information. **All** information submitted as compliance with permit conditions must be submitted to the nearest District Service Center **and** should include the above referenced permit number.

Please be advised that the period of time within which a third party may request an administrative hearing on this permit may not have expired by the date of issuance. **A** potential petitioner has twenty-six (26) days from the date on which the actual notice is deposited in the mail, or twenty-one (21) days from publication of this notice when actual notice is not provided, within which to file a petition for an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes. Receipt of such a petition by the District may result in this permit becoming null and void.

Sincerely,

Gloria Lewis, Director
Permit Data Services Division

Enclosures: Permit, Conditions for Issuance, Compliance Forms, Map, Well Tags

cc: District Permit File

GOVERNING BOARD

William Kerr, CHAIRMAN MELBOURNE BEACH
Ometrias D Long VICE CHAIRMAN APOPKA
Jeff X Jennings, SECRETARY MAITLAND
Duane Ottenstroer, TREASURER JACKSONVILLE
Ann T Moore BUNNELL
Michael Branch FERNANDINA BEACH
Catherine A Walker ALTAMONTE SPRINGS
Clay Albright EAST LAKE WEIR
David G Graham JACKSONVILLE

PERMIT NO. 10652 **DATE ISSUED:** October 9, 2001
PROJECT Cape Canaveral Plant

A PERMIT AUTHORIZING:

The District authorizes, as limited by the attached permit conditions, the use of up to 91.3 million gallons per year of groundwater from the Surficial aquifer, 54.75 million gallons per year from the Brevard County Sewer Authority, and 300,395 million gallons per year of surface water from the Indian River Lagoon for electrical power generation.

LOCATION:

Site: Cape Canavaral Plant
Brevard County
Section(s): 19 Township(s): 23S Range(s): 36E

ISSUED TO:

Florida Power and Light company
6000 North US Highway 1
Cocoa, FL 32927

Permittee agrees to hold and save the St. Johns River Water Management District and its successors harmless from any and all damages, claims, or liabilities which may arise from permit issuance. Said application, including all maps and specifications attached thereto, is by reference made a part hereof.

This permit does not convey to permittee any property rights nor any rights of privileges other than those specified herein, nor relieve the permittee from complying with any law, regulation or requirement affecting the rights of other bodies or agencies. All structures and works installed by permittee hereunder shall remain the property of the permittee.

This permit may be revoked, modified or transferred at any time pursuant to the appropriate provisions of Chapter 373, Florida Statutes and 40C-1, Florida Administrative Code.

PERMIT IS CONDITIONED UPON:

See conditions on attached "Exhibit A", dated October 9, 2001

AUTHORIZED BY: St. Johns River Water Management District
Department of Resource Management

By: _____
Harold A. Wilkening III
Director

By: _____
Kirby B. Green, III
Assistant Secretary

"EXHIBIT A"
CONDITIONS FOR ISSUANCE OF PERMIT NUMBER 10652
FLORIDA POWER AND LIGHT COMPANY
DATED OCTOBER 9,2001

1. District Authorized 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.

2. Nothing in this permit should be construed to limit the authority of the St. Johns River Water Management District to declare a water shortage and issue orders pursuant to Section 373.175, Florida Statutes, or to formulate a plan for implementation during periods of water shortage, pursuant to Section 373.246, Florida Statutes. In the event a water shortage, is declared by the District Governing Board, the permittee must adhere to the water shortage restriction as specified by the District, even though the specified water shortage restrictions may be inconsistent with the terms and conditions of this permit.

3. Prior to the construction, modification, or abandonment of a well, the permittee must obtain a Water Well Construction Permit from the St. Johns River Water Management District, or the appropriate local government pursuant to Chapter 40C-3, Florida Administrative Code. Construction, modification, or abandonment of a well will require modification of the consumptive use permit when such construction, modification or abandonment is other than that specified and described on the consumptive use permit application form.

4. Leaking or inoperative well casings, valves, or controls must be repaired or replaced as required to eliminate the leak or make the system fully operational.

5. Legal uses of water existing at the time of the permit application may not be interfered with by the consumptive use. If unanticipated interference occurs, the District may revoke the permit in whole or in part to curtail or abate the interference unless the permittee mitigates for the interference. In those cases where other permit holders are identified by the District as also contributing to the interference, the permittee may choose to mitigate in a cooperative effort with these other permittees. The permittee must submit a mitigation plan to the District for approval prior to implementing such mitigation.

6. Off-site land uses existing at the time of permit application may not be significantly adversely impacted as a result of the consumptive use. If unanticipated significant adverse impacts occur, the District shall revoke the permit in whole or in part to

curtail or abate the adverse impacts, unless the impacts can be mitigated by the permittee.

7. The District must be notified, in writing, within 30 days of any sale, conveyance, or other transfer of a well or facility from which the permitted consumptive use is made or within 30 days of any transfer of ownership or control of the real property at which the permitted consumptive use is located. All transfers of ownership or transfers of permits are subject to the provisions of section 40C-1.612, Florida Administrative Code.

8. A District-issued identification tag shall be prominently displayed at each withdrawal site by permanently affixing such tag to the pump, headgate, valve or other withdrawal facility as provided by Section 40C-2.401, Florida Administrative Code. Permittee shall notify the District in the event that a replacement tag is needed.

9. Landscape irrigation is prohibited between the hours of 10:00 a.m. and 4:00 p.m., except as follows:

a) Irrigation using a micro-irrigation system is allowed anytime.

(b) The use of reclaimed water for irrigation is allowed anytime, provided appropriate signs are placed on the property to inform the general public and District enforcement personnel of such use. Such signs must be in accordance with local restrictions.

(c) Irrigation of, or in preparation for planting, new landscape is allowed any time of day for one 30 day period provided irrigation is limited to the amount necessary for plant establishment.

(d) Watering in of chemicals, including insecticides, pesticides, fertilizers, fungicides, and herbicides when required by law, the manufacturer, or best management practices is allowed anytime within 24 hours of application.

(e) Irrigation systems may be operated anytime for maintenance and repair purposes not to exceed ten minutes per hour per zone.

10. All submittals made to demonstrate compliance with this permit shall have the CUP number 10652 plainly labeled on the submittal.

11. This permit will expire 20 years from the date of issuance.

12. The maximum annual groundwater withdrawal from the Surficial aquifer for electrical power generation must not exceed 91.3 million gallons in the years 2001 through 2006.

13. The maximum daily groundwater withdrawals must not exceed 0.562 million gallons.

14. If the use of reclaimed water from the Brevard County Sewer Authority is deemed feasible, the maximum annual groundwater withdrawal from the Surficial aquifer for electrical power generation must not exceed 36.55 million gallons in years 2007 through 2021 (based on an available reclaimed volume of 0.15 million gallons per day from the Brevard County Port St. John Wastewater Facility). If a connection to the Brevard County Port St. John Wastewater Facility has not been completed then the maximum annual groundwater withdrawal from the Surficial aquifer for electrical power generation must not exceed 91.3 million gallons until the time that connection to reclaimed is complete

15. Maximum annual withdrawals from Surficial aquifer as an emergency backup for electrical power generation must not exceed 54.75 million gallons in the years 2007 through 2021. All available reclaimed water must be utilized prior to using groundwater. The use of groundwater as an emergency supplemental source must be reported separately along with the EN-50 reports outlined in Other Permit Condition No. 10. Documentation verifying the insufficient reclaimed water availability must also be included.

16. The annual surface withdrawal from the Indian River Lagoon for electrical power generation must not exceed 300,395 million gallons per year in the year 2001 through 2021.

17. By December 31, 2003, the permittee must submit a reuse feasibility report to the District. The report must include an executed contractual agreement with Brevard County Sewer Authority that requires the Brevard County Sewer Authority to provide, and the permittee to take and utilize, a minimum of 0.15 million gallons per day of reclaimed water based on an annual average basis. The report must also evaluate whether reclaimed water quality for 2000, 2001, 2002, and the first half of 2003 will meet the permittee's requirements and include a cost evaluation to design, manufacture and install a water delivery system and a dual source water supply system.

18. The use of reclaimed water from the Brevard County Sewer Authority must be implemented by December 31, 2006, if deemed feasible by District staff.

19. The lowest quality water source, such as reclaimed water and surface/storm

water, must be used as irrigation water and process water when available and deemed feasible pursuant to District rules and applicable state law.

20. The permittee has elected to implement an alternative method for Surficial aquifer wells **2 (4277), 3 (4278), 4 (33152), 5 (4280), 6 (4281), 7 (33153), 8 (4283), 9 (4284), 10 (4285), 11 (4286), 12 (4287),** and **13 (4288)** which utilizes an hour meter in conjunction with the measured flow rate for the well as a basis for calculating the quantity of water withdrawn from the well. The method must be implemented as documented in the Alternative Method Criteria Checklist. The permittee may not alter the approved alternative method without prior written approval from the District. The method must maintain 90% accuracy and be verifiable. If after a period of one year, the selected alternative does not meet the accuracy criteria, totalizing flow meters or another District-approved alternative must be used. If flow meters are used, the meters must maintain **95%** accuracy, be verifiable and be installed according to manufacturer specifications.

21. Total withdrawal from surficial aquifer wells **2 (4277), 3 (4278), 4 (33152), 5 (4280), 6 (4281), 7 (33153), 8 (4283), 9 (4284), 10 (4285), 11 (4286), 12 (4287),** and **13 (4288),** the proposed reclaimed interconnection point **P-1 (34017),** and from the Indian River Lagoon must be recorded continuously, totaled monthly, and reported to the District every six months for the duration of the permit using District Form No. **EN-50.** The reporting dates each year will be as follows:

Reporting Period	Report Due Date
January - June	July 31
July - December	January 31

22. The permittee must maintain the meters. In case of failure or breakdown of any meter, the District must be notified in writing within **5** days of its discovery. The defective meter must be repaired or replaced within **30** days of its discovery.

23. If flow meters are installed in place of the hour meters on wells **2 (4277), 3 (4278), 4 (33152), 5 (4280), 6 (4281), 7 (33153), 8 (4283), 9 (4284), 10 (4285), 11 (4286), 12 (4287),** and **13 (4288)** then the permittee must have the flow meters calibrated once every 3 years within **30** days of the anniversary date of permit issuance, and recalibrated if the difference between the actual flow and the meter reading is greater than **5%.** District Form **No. EN-51** must be submitted to the District within **10** days of the inspection/ calibration.

24. The permittee must have wells 5 **(4280)** and **8 (4283)** rehabilitated and put into production within three years of issuance of this permit.

25. The permittee must follow the proposed well field management plan which includes pumping the wells in the following groups: Group I - wells 6 (4281), 11 (4286), 13 (4288) ;Group II - wells 3 (4278), 9 (4284), and 12 (4287) ;Group III - wells 2 (4277), 4 (33152), 7 (33153), and 10 (4285) . The pumping schedule must rotate well groups every 5th day. If the District determines that unacceptable saline water intrusion is occurring as a result of the withdrawals authorized by this permit, the District shall revoke the permit in whole or in part to curtail or abate the saline water intrusion.

26. Water samples for chloride must be collected every two months from Surficial aquifer wells 2 (4277), 3 (4278), 4 (33152), 5 (4280), 6 (4281), 7 (33153), 8 (4283), 9 (4284), 10 (4285), 11 (4286), 12 (4287), and 13 (4288) by the permittee, in accordance with a District approved QNQC program for chloride. The results of the analysis must be submitted to the District starting July 31, . 2002 and then every six months for the duration of the permit along with the mid-year water use submittals following the sampling event. If an evaluation of two years of chloride data indicates that unacceptable saline water intrusion is not occuring, then the chloride sampling frequency may be decreased to semi-annually. If the District determines that unacceptable saline water intrusion is occurring as a result of the withdrawals authorized by this permit, the District shall revoke the permit in whole or in part to curtail or abate the saline water intrusion.

27. Water quality samples must be collected from Surficial aquifer wells 2 (4277), 6 (4281), 8 (4283), 10 (4285), and 12 (4287) by the permittee, in accordance with a District approved QNQC program once a year beginning on May 15, 2002. The samples shall be analyzed for the following parameters: pH, Ca, Cl, Mg, Na, K, SO4, CO3, HCO3, total dissolved solids, total alkalinity, chloride, and total hardness.
The results will be submitted to the District with the mid-year water use submittals following the sampling event. All major ion analyses must be performed on filtered samples, and must be checked for a cation-anion balance of less than 10%. If a 10% error margin is exceeded in either sample, an additional sample must be collected within 24 hours and reanalyzed.
If the District determines that unacceptable saline water intrusion is occurring as a result of the withdrawals authorized by this permit, the District shall revoke the permit in whole or in part to curtail or abate the saline water intrusion.

28. The permittee shall submit, to the District, a compliance report pursuant to subsection 373.236(3), F.S., 5, 10 and 15 years after permit issuance. Specifically, the permittee shall submit the report by October 15 of the years 2006, 2011, and 2016. The report shall contain sufficient information to demonstrate that the permittee's use of water will continue, for the remaining

duration of the permit, to meet the conditions for permit issuance set forth in the District rules that existed at the time the permit was issued by the District. At a minimum, the compliance report must:

a.) meet the submittal requirements of section 4.2 of the Applicant's Handbook: Consumptive Uses of Water, February 8, 1999;

b.) include documentation verifying that the source is capable of supplying the needs authorized by this permit without causing harm to water resources;

c.) include documentation verifying that use of water is efficient and that the permittee is implementing all feasible water conservation measures;

d.) document that significant saltwater intrusion is not occurring; and

e.) include information documenting that the projected allocation is needed.

St. JOHN'S RIVER WATER MANAGEMENT DISTRICT

CONSUMPTIVE USE PERMIT NO. 9202

SANFORD PLANT

RRL-4
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT _____
PAGES 1-24

Henry Dean, Executive Director
John R. Wehle, Assistant Executive Director

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT

POST OFFICE BOX 1429 PALATKA, FLORIDA 32178-1429
TELEPHONE 904-329-4500 SUNCOM 904-860-4500
TDD 9043294450 TDD SUNCOM 6604450
FAX (Executive) 329-4125 (Legal) 329-4465 (Permitting) 329-4315 (Administration/Finance) 329-4508

SERVICE CENTERS

616 E South Street 7775 Baymeadows way PERMITTING OPERATIONS

Orlando 407-897-4300 Florida 32207 Jacksonville Suite 102 Florida 32937 Melbourne East Drive Florida 32901-3317 Melbourne Florida 32935-8109
TDD 407-897-5960 904-730-6270 407-984-4940 407-752-3100
TDO 904-448-7900 TDO 407-722-5368 TDO 407-752-3102

June 13, 2000

FLORIDA POWER AND LIGHT COMPANY
950 South Highway 17-92
De Bary, FL 32713

SUBJECT: Consumptive Use Permit Number 9202
FLORIDA POWER AND LIGHT COMPANY

Dear Sir/Madam:

Enclosed is your permit and the forms necessary for submitting information to comply with conditions of the permit as authorized by the St. Johns River Water Management District on June 13, 2000.

Permit issuance does not relieve you from the responsibility of obtaining permits from any federal, state and/or local agencies asserting concurrent jurisdiction over this work.

The enclosed permit is a legal document and should be kept with your other important records. Please read the permit and conditions carefully since the referenced conditions may require submittal of additional information. All information submitted as compliance with permit conditions must be submitted to the nearest District Service Center and should include the above referenced permit number.

Please be advised that the period of time within which a third party may request an administrative hearing on this permit may not have expired by the date of issuance. A potential petitioner has twenty-six (26) days from the date on which the actual notice is deposited in the mail, or twenty-one (21) days from publication of this notice when actual notice is not provided, within which to file a petition for an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes. Receipt of such a petition by the District may result in this permit becoming null and void.

Sincerely,

Gloria Jean Lewis

Gloria Lewis, Director
Permit Data Services Division

Enclosures: Permit, Conditions for Issuance, Compliance Forms, Map,Well Tags

cc: District Permit File

Dan Roach, CHAIRMAN FERNANDINA BEACH
Duane Ottenstroer, TREASURER SWITZERLAND
Otis Mason, SECRETARY ST. AUGUSTINE
William Kerr MELBOURNE BEACH
Jeff K. Jennings MAITLAND
William M. Segal MAITLAND
Ometrias D. Long APOPKA
Clay Albright EAST LAKE WEIR
Reid Hughes DAYTONA BEACH

PERMIT NO. 9202 **DATE ISSUED:** June 13, 2000
PROJECT NAME: FLORIDA POWER AND LIGHT COMPANY

A PERMIT AUTHORIZING:

The District authorizes, as limited by the attached permit conditions, the use of up to 65778.8 million gallons per year of surface water from the St Johns River and up to 182.5 million gallons per year of ground water from the Floridan aquifer system for commercial industrial use.

LOCATION:

Site: FLORIDA POWER AND LIGHT COMPANY
Volusia County

Section(s):	22, 31, 32	Township(s):	18S	Range(s):	30E
	4, 5, 6, 8, 9, 16		19S		30E

ISSUED TO:
FLORIDA POWER AND LIGHT COMPANY
950 South Highway 17-92
De Bary, FL 32713

Permittee agrees to hold and save the St. Johns River Water Management District and its successors harmless from any and all damages, claims, or liabilities which may arise from permit issuance. Said application, including all maps and specifications attached thereto, is by reference made a part hereof.

This permit does not convey to permittee any property rights nor any rights of privileges other than those specified herein, nor relieve the permittee from complying with any law, regulation or requirement affecting the rights of other bodies or agencies. All structures and works installed by permittee hereunder shall remain the property of the permittee.

This permit may be revoked, modified or transferred at any time pursuant to the appropriate provisions of Chapter 373, Florida Statutes and 40C-1, Florida Administrative Code.

PERMIT IS CONDITIONED UPON:

See conditions on attached "Exhibit A", dated June 13, 2000

AUTHORIZED BY: St. Johns River Water Management District
Department of Resource Management

By: _____
Hal Wilkening
Director

By: _____
Henry Dean
Assitant Secretary

"EXHIBIT A"
CONDITIONS FOR ISSUANCE OF PERMIT NUMBER 9202
FLORIDA POWER AND LIGHT COMPANY
DATED JUNE 13, 2000

1. District Authorized 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.

2. Nothing in this permit should be construed to limit the authority of the St. Johns River Water Management District to declare a water shortage and issue orders pursuant to Section 373.175, Florida Statutes, or to formulate a plan for implementation during periods of water shortage, pursuant to Section 373.246, Florida Statutes. In the event a water shortage, is declared by the District Governing Board, the permittee must adhere to the water shortage restriction as specified by the District, even though the specified water shortage restrictions may be inconsistent with the terms and conditions of this permit.

3. Prior to the construction, modification, or abandonment of a well, the permittee must obtain a Water Well Construction Permit from the St. Johns River Water Management District, or the appropriate local government pursuant to Chapter 40C-3, Florida Administrative Code. Construction, modification, or abandonment of a well will require modification of the consumptive use permit when such construction, modification or abandonment is other than that specified and described on the consumptive use. permit application form.

4. Leaking or inoperative well casings, valves, or controls must be repaired or replaced as required to eliminate the leak or make the system fully operational.

5. Legal uses of water existing at the time of the permit application may not be interfered with by the consumptive use. If unanticipated interference occurs, the District may revoke the permit in whole or in part to curtail or abate the interference unless the permittee mitigates for the interference. In those cases where other permit holders are identified by the District as also contributing to the interference, the permittee may choose to mitigate in a cooperative effort with these other permittees. The permittee must submit a mitigation plan to the District for approval prior to implementing such mitigation.

6. Off-site land uses existing at the time of permit application may not be significantly adversely impacted as a result of the consumptive use. If unanticipated significant adverse impacts occur, the District shall revoke the permit in whole or in part to curtail or abate the adverse impacts, unless the impacts can be mitigated by the

permittee.

7. The District must be notified, in writing, within 30 days of any sale, conveyance, or other transfer of a well or facility from which the permitted consumptive use is made or within 30 days of any transfer of ownership or control of the real property at which the permitted consumptive use is located. All transfers of ownership or transfers of permits are subject to the provisions of section 40C-1.612, Florida Administrative Code.

8. A District-issued identification tag shall be prominently displayed at each withdrawal site by permanently affixing such tag to the pump, headgate, valve or other withdrawal facility as provided by Section 40C-2.401, Florida Administrative Code. Permittee shall notify the District in the event that a replacement tag is needed.

9. Permittee must implement the conservation plan approved by the District in accordance with the schedule contained therein. A report detailing the progress of plan implementation must be submitted to the District on or before the midpoint of the permit duration.

10. All submittals made to demonstrate compliance with this permit must have the CUP number 9202 plainly labeled on the submittal.

11. This permit will expire twenty (20) years from the date of issuance.

12. Maximum annual ground water withdrawals for commercial industrial use must not exceed:

182.5 million gallons in 2000 through 2002,
103.7 million gallons in 2003 through 2020.

13. The maximum annual surface water surface water withdrawals for commercial industrial use must not exceed:

65,700 million gallons in 2000 through 2002,
65778.8 million gallons in 2003 through 2020.

14. The maximum daily surface water withdrawals for cooling and circulating must not exceed 270 million gallons per day.

15. The lowest quality water source, such as surface -water or reclaimed water, must be used as commercial industrial water in place of ground water when available and deemed feasible pursuant to District rules and applicable state law.

16. Within 6 months of permit issuance, wells 3 (No. 17680) and 4 (No. 17681) and pumps CW3A (No. 2956), CW 3B (No. 2957), OCW 3A (No. 22455) OCW 3B (No. 22454) and proposed pumps LF 3A (No. 22457) and LF 3B (No. 22456) must be equipped with totalizing flow meters or an alternative method for measuring flow must be implemented. The method must be implemented as documented in the permit application received by the District on August 9, 1999.

The permittee has elected to implement an alternative method for pumps CW3A (No. 2956), CW 3B (No. 2957), OCW 3A (No. 22455) OCW 3B (No. 22454) and proposed pumps LF 3A (No. 22457) and LF 3B (No. 22456) where the pump on/off times are electronically recorded. The flow is determined using the running times of the pumps and the appropriate pump log curves and pump rate as a basis for calculating the quantity of water withdrawn from the St Johns River. The permittee may not alter the approved alternative method without prior written approval from the District. The method must maintain 90% accuracy and be verifiable. If after a period of one year, the selected alternative method does not meet the accuracy criteria, a totalizing flow meter or another District-approved alternative must be used. If flow meters are used, the meters must maintain 95% accuracy, be verifiable and be installed according to manufacturer specifications. Documentation of proper installation of the flow meter may be accomplished by a site visit by District staff, or by submitting a copy of the manufacturer's specifications and a photograph within 30 days of meter installation.

17. The permittee must maintain all meters or other District approved flow measuring devices. In case of failure or breakdown of any meter or other device, the District must be notified in writing within 5 days of its discovery. A defective meter or other device must be repaired or replaced within 30 days of its discovery.

18. If utilized, the permittee must have all flow meters checked for accuracy at least once every 3 years within 30 days of the anniversary date of permit issuance, and recalibrated if the difference between the actual flow and the meter reading is greater than 5%. District Form No. EN-51 must be submitted to the District within 10 days of the inspection/calibration.

19. Total withdrawal, from well numbers 3 (No. 17680) and 4 (No. 17681), and pumps CW3A (No. 2956), CW 3B (No. 2957), OCW 3A (No. 22455) OCW 3B (No. 22454) and proposed pumps LF 3A (No. 22457) and LF 3B (No. 22456) as listed on the application, must be recorded continuously, totaled monthly, and reported to the District every six months for the duration of the permit using District Form No. EN-50. The reporting dates each year will be as follows:

Reporting Period	Report Due Date

January - June	July 31
July - December	January 31

20. Water samples must be collected in May every odd numbered year starting in 2001 from well number 3 (No. 17680) and submitted to a Department of Health and Rehabilitative Services or Florida Department of Environmental Protection approved laboratory for analysis. All water samples shall be analyzed for the following:

Calcium	Total Alkalinity
Sodium	Magnesium
Chlorides	Total Hardness
pH	Carbonate

All major ion analyses shall be conducted on filtered samples, and shall be checked for a cation-anion balance of less than 10%. If this 10% error margin is exceeded in any sample, an additional sample shall be collected immediately and reanalyzed. Results of these tests shall be submitted to the District by July 31 along with EN-50 reports. If the District determines that unacceptable saline water intrusion is occurring as a result of the withdrawals authorized by this permit, the District shall revoke the permit in whole or in part to curtail or abate the saline water intrusion.

21. The permittee shall submit, to the District, a compliance report pursuant to subsection **373.236(3),** F.S., 5, 10, 15, and 20 years after permit issuance. Specifically, the permittee shall submit the reports by June 14, 2005, June 14, 2010, June **14, 2015,** and June **14, 2020.** The reports shall contain sufficient information to demonstrate that the permittee's use of water will continue, for the remaining duration of the permit, to meet the conditions for permit issuance set forth in the District rules that existed at the time the permit was issued by the District. At a minimum, the compliance report must:

(a) meet the submittal requirements of section 4.2 of the Applicant's Handbook: Consumptive Uses of Water, February 8, 1999;

(b) include documentation verifying that the source is capable of supplying the needs authorized by this permit without causing harm to water resources:

(c) include documentation verifying that the permittee is implementing all feasible water conservation measures;

(d) document that the lowest acceptable quality water source, including reclaimed water or surface water (which includes storm water), must be utilized for each consumptive use;

(e) ensure that all monitoring requirements are met;

(f) document that significant saltwater intrusion is not occurring; and include information documenting that the projected allocation is needed.

36204

St. Johns River Water Management Distric
P. O. Box 142
Palatka, Florida 32178-142

WATER USE RECORD FORM EN • 50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME 3 PUMP NAME

COMPLETE THE FORM BY PRINTING EACH "NUMBER" WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. MARK ALL THAT APPLY

0 NO USE THIS PERIOD 0 WELL CAPPED

0 WELL ABANDONED (40C-3, FAC) O PROPERTY SOLD

O COMMENTS: (PLEASE PRINT): _____

_____

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

		GALLONS	OR METER READING:
JAN	00		
FEB	00		
MAR	00		
APR	00		
MAY	00		
JUN	00		

Step 3. CONTACT NAME _____

PHONE NUMBER _____

17680

362041

St. Johns River Water Management Distri
P. 0. Box 142
Palatka, Florida 32178-1 42

WATER USE RECORC FORM EN - 50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME 4 PUMP NAME

COMPLETE THE FORM BY PRINTING EACH "NUMBER" WITHOUTTOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. MARK ALL THAT APPLY

- O NO USE THIS PERIOD
- O WELL CAPPED
- O WELL ABANDONED (40C-3, FAC)
- O PROPERTY SOLD
- O COMMENTS: (PLEASE PRINT): _____

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

	GALLONS	OR METER READING5
JAN 00		
FEB 00		
MAR 00		
APR 00		
MAY 00		
JUN 00		

Step 3. CONTACT NAME _____

PHONE NUMBER _____

17681

[redacted]

362041

St. Johns River Water Management Distric
P. 0. Box 1422
Palatka, Florida 32178-142

WATER USE RECORC FORM EN - 50

CUP# 9 2 0 2 PERMIT ISSUE DATE 13-jun-2000

)ISTRICT ID OWNERS ID

'ERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

VELL NAME CW3A PUMP NAME

COMPLETE THE FORM BY PRINTING EACH 'NUMBER' WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. MARK ALL THAT APPLY

0 NO USE THIS PERIOD 0 WELL CAPPED

0 WELL ABANDONED (40C-3, FAC) O PROPERTY SOLD

O COMMENTS: (PLEASE PRINT): _____

_____

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

	GALLONS	OR METER READING:
JAN 00		
FEB 00		
MAR 00		
APR 00		
MAY 00		
JUN 00		

itep 3. CONTACT NAME _____

PHONE NUMBER _____

2956

[redacted]

36204

St. Johns River Water Management Distri
P. 0. Box 1422
Palatka, Florida 32178-1 42

WATER USE RECORD FORM EN • 50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME CW3B PUMP NAME

COMPLETE THE FORM BY PRINTING EACH 'NUMBER" WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. MARK ALL THAT APPLY

0 NO USE THIS PERIOD 0 WELL CAPPED

0 WELL ABANDONED (40C-3, FAC) O PROPERTY SOLD

O COMMENTS: (PLEASE PRINT): _____

_____

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

	GALLONS	OR METER READING:
JAN 00		
FEB 00		
MAR 00		
APR 00		
MAY 00		
JUN 00		

Step 3. CONTACT NAME _____

PHONE NUMBER _____

2957

362041

St. Johns River Water Management Distri
P. 0. Box 1422
Palatka, Florida 32178-142

WATER USE RECORD FORM EN •50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME LF3A PUMP NAME

COMPLETE THE FORM BY PRINTING EACH 'NUMBER" WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. MARK ALL THAT APPLY

0 NO USE THIS PERIOD 0 WELL CAPPED

0 WELL ABANDONED (40C-3, FAC) O PROPERTY SOLD

O COMMENTS: (PLEASE PRINT): _____

_____

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

	GALLONS	OR METER READING:
JAN 00		
FEB 00		
MAR 00		
APR 00		
MAY 00		
JUN 00		

Step 3. CONTACT NAME _____

PHONE NUMBER _____

22457

36204

St. Johns River Water Management Distri
P. 0. Box 142
Palatka, Florida 32178-142

WATER USE RECORD FORM EN • 50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME LF3B PUMP NAME

COMPLETE THE FORM BY PRINTING EACH 'NUMBER' WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. MARK ALL THAT APPLY

0 NO USE THIS PERIOD 0 WELL CAPPED

0 WELL ABANDONED (40C-3, FAC) O PROPERTY SOLD

O COMMENTS: (PLEASE PRINT): _____

_____

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

	GALLONS	OR METER READING:
JAN 00		
FEB 00		
MAR 00		
APR 00		
MAY 00		
JUN 00		

Step 3. CONTACT NAME _____

PHONE NUMBER _____

22456

362041

St. Johns River Water Management Distric
P. 0. Box 142
Palatka, Florida 32178-142

WATER USE RECORD FORM EN-50

CUP# 9202 PERMIT ISSUE DATE 13-jun-2000

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT FLORIDA POWER AND LIGHT COMPANY

WELL NAME OCW3A PUMP NAME

COMPLETE THE FORM BY PRINTING EACH 'NUMBER' WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. MARK ALL THAT APPLY

0 NO USE THIS PERIOD 0 WELL CAPPED

0 WELL ABANDONED (40C-3, FAC) O PROPERTY SOLD

O COMMENTS: (PLEASE PRINT): _____

_____

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

	GALLONS	OR METER READING:
JAN 00		
FEB 00		
MAR 00		
APR 00		
MAY 00		
JUN 00		

Step 3. CONTACT NAME _____

PHONE NUMBER _____

22455

36204

St. Johns River Water Management Distric
P. 0. Box 1422
Palatka, Florida 32178-I 42'

WATER USE RECORC **FORM EN • 50**

CUP# **9202** PERMIT ISSUE DATE **13-jun-2000**

DISTRICT ID OWNERS ID

PERMITTEE FLORIDA POWER AND LIGHT PROJECT **FLORIDA POWER AND LIGHT COMPANY**

WELL NAME **OCW3B** PUMP NAME

COMPLETE THE FORM BY PRINTING EACH 'NUMBER" WITHOUT TOUCHING THE SIDES OF THE BOX

0	1	2	3	4	5	6	7	8	9

Step 1. MARK ALL THAT APPLY

0 NO USE THIS PERIOD o WELL CAPPED

0 WELL ABANDONED (40C-3, FAC) O PROPERTY SOLD

O COMMENTS: (PLEASE PRINT): _____

_____

Step 2. REPORT MONTHLY WATER USE BELOW. RECORD EITHER FLOW METER READINGS OR GALLONS USED (NOT BOTH).

		GALLONS	**OR METER READING:**
JAN	**00**		
FEB	**00**		
MAR	**00**		
APR	**00**		
MAY	**00**		
JUN	**00**		

Step 3. CONTACT NAME _____

PHONE NUMBER _____

224'54

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: **9202**

ermittee Name: **FLORIDA POWER AND LIGHT COMPANY**

ate of Permit Issuance: **June 13, 2000** Station Name: **3**

ump Capacity: **200 GPM**

erial Number on Meter: _____

eter Model: _____

ischarge Pipe Diameter: _____

ate of Last Meter Calibration: _____/_____/_____

ate of This Calibration: _____/_____/_____

ame of Person Performing Calibration: _____

_____

ethod or Equipment Used for Calibration: _____

_____

itial Meter Reading at Start of Calibration: _____

nal Meter Reading at End of Calibration: _____

eadings on Equipment Used for Calibration:

Start: _____ End: _____

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: _____%

ame of Person Completing Form (Please Print): _____

ompany Name: _____

ddress: _____

ity/State/Zip: _____

aytime Telephone: (_____) _____ - _____

Please Retain a Copy for Your Records . .

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: **9202**

ermittee Name: **FLORIDA POWER AND LIGHT COMPANY**

ate of Permit Issuance: **June 13, 2000** Station Name: **4**

ump Capacity: **200 GPM**

erial Number on Meter: _____

eter Model: _____

ischarge Pipe Diameter: _____

ate of Last Meter Calibration: _____/_____/_____

ate of This Calibration: _____/_____/_____

ame of Person Performing Calibration: _____

_____

ethod or Equipment Used for Calibration: _____

_____

itial Meter Reading at Start of Calibration: _____

nal Meter Reading at End of Calibration: _____

eadings on Equipment Used for Calibration:

Start: _____ End: _____

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: _____%

ame of Person Completing Form (Please Print): _____

ompany Name: _____

ddress: _____

ity/State/Zip: _____

aytime Telephone: (_____) _____ - _____

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: **9202**

ermittee Name: **FLORIDA POWER AND LIGHT COMPANY**

ate of Permit Issuance: **June 13, 2000** Station Name: **CW3A**

ump Capacity: **65000 GPM**

erial Number on Meter: _____

leter Model: _____

ischarge Pipe Diameter: _____

ate of Last Meter Calibration: _____/_____/_____

ate of This Calibration: _____/_____/_____

ame of Person Performing Calibration: _____

_____

lethod or Equipment Used for Calibration: _____

_____

itial Meter Reading at Start of Calibration: _____

inal Meter Reading at End of Calibration: _____

teadings on Equipment Used for Calibration:

Start: _____ End: _____

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: _____%

ame of Person Completing Form (Please Print): _____

ompany Name: _____

ddress: _____

ity/State/Zip: _____

aytime Telephone: (_____) _____ - _____

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: **9202**

ermittee Name: **FLORIDA POWER AND LIGHT COMPANY**

ate of Permit Issuance: **June 13, 2000** Station Name: **CW3B**

ump Capacity: **65000 GPM**

erial Number on Meter: _____

eter Model: _____

ischarge Pipe Diameter: _____

ate of Last Meter Calibration: _____/_____/_____

ate of This Calibration: _____/_____/_____

ame of Person Performing Calibration: _____

_____

ethod or Equipment Used for Calibration: _____

_____

itial Meter Reading at Start of Calibration: _____

inal Meter Reading at End of Calibration: _____

eadings on Equipment Used for Calibration:

Start: _____ End:_____

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: _____%

ame of Person Completing Form (Please Print): _____

ompany Name: _____

ddress: _____

ity/State/Zip: _____

aytime Telephone: (_____) _____ - _____

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: **9202**

ermittee Name: **FLORIDA POWER AND LIGHT COMPANY**

ate of Permit Issuance: **June 13, 2000** Station Name: **LF3A**

ump Capacity: **10000 GPM**

erial Number on Meter: _____

eter Model: _____

scharge Pipe Diameter: _____

ate of Last Meter Calibration: _____/_____/_____

ate of This Calibration: _____/_____/_____

ame of Person Performing Calibration: _____

_____

ethod or Equipment Used for Calibration: _____

_____

itial Meter Reading at Start of Calibration: _____

nal Meter Reading at End of Calibration: _____

eadings on Equipment Used for Calibration:

Start: _____ End: _____

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: _____%

ame of Person Completing Form (Please Print): _____

ompany Name: _____

ddress: _____

ty/State/Zip: _____

aytime Telephone: (_____) _____ - _____

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: **9202**

ermittee Name: **FLORIDA POWER AND LIGHT COMPANY**

ate of Permit Issuance: **June 13, 2000** Station Name: **LF3B**

ump Capacity: **10000 GPM**

erial Number on Meter: _____

eter Model: _____

ischarge Pipe Diameter: _____

ate of Last Meter Calibration: _____/_____/_____

ate of This Calibration: _____/_____/_____

ame of Person Performing Calibration: _____

_____

ethod or Equipment Used for Calibration: _____

_____

itial Meter Reading at Start of Calibration: _____

nal Meter Reading at End of Calibration: _____

eadings on Equipment Used for Calibration:

Start: _____ End: _____

(Attach Formulas Used to Make Calculations)

rcent of Error Between Meter Reading and Calibration Equipment: _____%

ame of Person Completing Form (Please Print): _____

ompany Name: _____

dress: _____

ity/State/Zip: _____

aytime Telephone: (_____) _____ - _____

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: **9202**

ermittee Name: **FLORIDA POWER AND LIGHT COMPANY**

ate of Permit Issuance: **June 13, 2000** Station Name: **OCW3A**

ump Capacity: **4514 GPM**

erial Number on Meter: _____

eter Model: _____

ischarge Pipe Diameter: _____

ate of Last Meter Calibration: _____/_____/_____

ate of This Calibration: _____/_____/_____

ame of Person Performing Calibration: _____

_____

lethod or Equipment Used for Calibration: _____

_____

itial Meter Reading at Start of Calibration: _____

inal Meter Reading at End of Calibration: _____

eadings on Equipment Used for Calibration:

Start: _____ End: _____

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: _____%

ame of Person Completing Form (Please Print): _____

ompany Name: _____

ddress: _____

ity/State/Zip: _____

aytime Telephone: (_____) _____ - _____

Please Retain a Copy for Your Records

FLOW METER WATER CALIBRATION RECORD - EN51

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

onsumptive Use Permit Number: **9202**

ermittee Name: **FLORIDA POWER AND LIGHT COMPANY**

ate of Permit Issuance: **June 13, 2000** Station Name: **OCW3B**

ump Capacity: **4514 GPM**

erial Number on Meter: _____

eter Model: _____

ischarge Pipe Diameter: _____

ate of Last Meter Calibration: _____/_____/_____

ate of This Calibration: _____/_____/_____

ame of Person Performing Calibration: _____

_____

ethod or Equipment Used for Calibration: _____

_____

itial Meter Reading at Start of Calibration: _____

nal Meter Reading at End of Calibration: _____

eadings on Equipment Used for Calibration:

Start: _____ End: _____

(Attach Formulas Used to Make Calculations)

ercent of Error Between Meter Reading and Calibration Equipment: _____%

ame of Person Completing Form (Please Print): _____

ompany Name: _____

ddress: _____

ity/State/Zip: _____

aytime Telephone: (_____) _____ - _____

Please Retain a Copy for Your Records

DRAFT

TITLE V AIR OPERATION PERMIT RENEWAL

PROPOSED PERMIT NO. 0110036-006-AV

RRL-5
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT _____
PAGES 1-40

Title V Air Operation Permit Renewal
PROPOSED Permit No. **0110036-006-AV**

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Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of four fossil fuel steam generators and twelve simple cycle combustion turbines.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the Title V permit renewal application received on April 24, 2003, this facility is a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1, rated at 225 MW, 2400 mmBtu/hr for natural gas and 2300 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, number 2 fuel oil, propane and on-specification used oil from FPL operations, with emissions exhausted through a 344 ft. stack.
002	Fossil Fuel Steam Generator, Unit 2, rated at 225 MW, 2400 mmBtu/hr for natural gas and 2300 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, number 2 fuel oil, propane and on-specification used oil from FPL operations, with emissions exhausted through a 344 ft. stack.
003	Fossil Fuel Steam Generator, Unit 3, rated at 402 MW, 4180 mmBtu/hr for natural gas and 4000 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, number 2 fuel oil, propane and on-specification used oil from FPL operations, with emissions exhausted through a 344 ft. stack.
004	Fossil Fuel Steam Generator, Unit 4, rated at 402 MW, 4180 mmBtu/hr for natural gas and 4000 mmBtu/hr for number 6 fuel oil, capable of burning any combination of natural gas, number 6 fuel oil, diesel fuel, propane and on-specification used oil from FPL operations, with emissions exhausted through a 344 ft. stack.
005	12 Simple Cycle Gas Turbines, GT1 through GT12, with a total capacity rated at 504 MW, 8424 mmBtu/hr, capable of burning any combination of, number 2 fuel oil and natural gas, with emissions exhausted through twelve 44 ft. stacks.

Unregulated Emissions Units and/or Activities	
017	Above ground fuel oil storage tanks
018	Miscellaneous internal combustion engines and portable equipment

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

These documents are provided to the permittee for information purposes only:
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements

These documents are on file with the permitting authority:
Title V Permit Renewal Application received on April 24, 2003.
DRAFT Title V Air Operation Permit Renewal clerked on June 5, 2003.
Letter from the applicant received on June 20, 2003.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. Appendix TV-4, Title V Conditions, is a part of this permit.
{Permitting note: Appendix TV-4, Title V Conditions, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. **Not Federally Enforceable.** General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rule 62-296.320(4)(b)1. & 4, F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 3346
Merrifield, VA 22116-3346
Telephone: 703/816-4434

and,

b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
[40 CFR 68]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6), and 62-4.040(1)(b), F.A.C.]

7. **Not Federally Enforceable.** General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying

known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. The owner or operator shall:

a. Tightly cover or close all VOC or OS containers when they are not in use.
b. Tightly cover all open tanks which contain VOC or OS when they are not in use.
c. Maintain all pipes, valves, fittings, etc., which handle VOC or OS in good operating condition.
d. Immediately confine and clean up VOC or OS spills and make sure wastes are placed in closed containers for reuse, recycling or proper disposal.

[Rule 62-296.320(1)(a), F.A.C.]

8. Not Federally Enforceable. No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity without taking reasonable precautions to prevent such emissions. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility shall include:

a. The facility shall construct temporary sandblasting enclosures when necessary, in order to perform sandblasting on fixed plant equipment.
b. Maintenance of paved areas shall be performed as needed.
c. Regular mowing of grass and care of vegetation shall be performed.
d. Access to plant property by unnecessary vehicles shall be limited.
e. Bagged chemical products shall be stored in weather-tight buildings until they are used.
f. Spills of powdered chemical products shall be cleaned up as soon as practicable.
g. Vehicles shall be restricted to slow speeds on the plant site.

[Rule 62-296.320(4)(c)2., F.A.C.; and proposed by applicant in the Title V permit renewal application received on April 24, 2003.]

9. When appropriate, any recording, monitoring or reporting requirements that are time-specific shall be in accordance with the effective date of this permit, which defines day one.
[Rule 62-213.440, F.A.C.]

10. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3)(a)2., F.A.C., shall be submitted to the Department and EPA within 60 (sixty) days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C.
[Rules 62-213.440(3) and 62-213.900, F.A.C.]

{Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2. & 3., F.A.C. (see Condition 51. of Appendix TV-4, Title V Conditions).}

11. Submittals. All reports, tests, notifications or other submittals required by this permit shall be submitted to the Broward County Department of Planning and Environmental Protection, Air Quality Division, and copies of those submittals shall be sent to the Department of Environmental Protection, Southeast District Office, Air Section. Addresses and telephone numbers are:

Broward County Department of Planning and Environmental Protection
Air Quality Division
218 SW 1st Avenue
Ft. Lauderdale, FL 33301
Phone: 954/519-1220

Department of Environmental Protection
Southeast District Office, Air Section
P.O. Box 15425
West Palm Beach, FL 33416
Phone: 561/681-6600

Any reports, data, notifications, certifications and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air & EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, GA 30303
Phone: 404/562-9155
Fax: 404/562-9163 or 404/562-9164

12. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information.
[Rule 62-213.420(4), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

Fossil fuel fired steam generators Unit 1 and Unit 2 are each 225 MW (electric) steam generators. The emissions units are fired on a variable combination of No. 6 fuel oil, No. 2 fuel oil, natural gas, propane, and on-specification used oil from FPL operations. When firing fuel oil, the maximum heat input for each boiler is 2300 mmBtu per hour, and when firing natural gas or propane, the maximum heat input for each boiler is 2400 mmBtu per hour.

Each emissions unit consists of a boiler that drives a turbine generator. Emissions are controlled with low NOx burners, and multiple cyclones for particulate matter (for the period 1/01/04 through 10/31/05 for Unit 001, and period 1/01/04 through 4/01/05 for Unit 002). Electrostatic precipitators shall replace the multiple cyclones beyond these dates. Each unit is equipped with a 344-foot stack. *Following the construction and installation of the ESPs at the facility, these emissions units will be subject to Compliance Assurance Monitoring (CAM) for those control devices. See Specific Condition* ***A.15.1.***

{Permitting note(s): These emissions units are regulated under Acid Rain, Phase II; and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator Unit 1 began commercial operation in 1960 and fossil fuel fired steam generator Unit 2 began commercial operation in 1961. These emissions units may inject additives such as magnesium hydroxide and related compounds into each boiler.}

The following specific conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	mmBtu/hr Heat Input*	Fuel Type
1	2400 2300	Natural Gas, Propane No. 2 or 6 Fuel Oil
2	2400 2300	Natural Gas, Propane No. 2 or 6 Fuel Oil

*When a blend of fuel oil and natural gas or propane is burned, the heat input is prorated based upon the percent heat input of each fuel.
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

A.2. Emissions Unit Operating Rate Limitation After Testing. Emissions units may be limited to the operating rate or conditions tested. See Specific Conditions **D.14.** and **A.15.** of this permit.
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation. Fuels. The only fuels allowed to be burned are any combination of No. 6 fuel oil, No. 2 fuel oil, natural gas, propane, and on-specification used oil from FPL operations.
[Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **A.4.1.** through **A.9.** are based on the specified averaging time of the applicable test method.}

A.4.1. Visible Emissions – Steady State Operation (effective 01/01/04 through 5/31/06 for Unit 001, and 01/01/04 through 10/31/05 for Unit 002). Visible emissions shall not exceed 40 percent opacity. Emissions units governed by this visible emissions standard shall conduct a compliance test for visible emissions annually using EPA Reference Method 9.
[Rule 62-296.405(1)(a), F.A.C.; and Order dated January 2, 1986 (Unit 1), and OGC Case No. 83-0578, Order dated April 24, 1984 (Unit 2).]

A.4.2. Visible Emissions – Steady State Operation (effective 6/01/06 for Unit 001, and 11/01/05 for Unit 002). Visible emissions shall not exceed 20 percent opacity. Emissions units governed by this visible emissions standard shall conduct a compliance test for visible emissions annually using EPA Reference Method 9.
[0110036-005-AC, Specific Condition A.16.]

A.5.1. Visible Emissions - Soot Blowing and Load Change (effective 01/01/04 through 5/31/06 for Unit 001, and 01/01/04 through 10/31/05 for Unit 002). Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition.

Note: these units have operational continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.]

A.5.2. Visible Emissions -- Soot Blowing and Load Change (effective 6/01/06 for Unit 001, and 11/01/05 for Unit 002). Visible emissions shall not exceed 40 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 40 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition.

Note: these units have operational continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.; and 0110036-005-AC, Specific Condition A.17.]

A.6.1. Particulate Matter – Steady State Operation (effective 01/01/04 through 5/31/06 for Unit 001, and 01/01/04 through 10/31/05 for Unit 002). Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

A.6.2. Particulate Matter – Steady State Operation (effective 6/01/06 for Unit 001, and 11/01/05 for Unit 002). Particulate matter emissions shall not exceed 0.03 pound per million Btu heat input, as measured by applicable compliance methods.
[0110036-005-AC, Specific Condition A.18.]

A.7.1. Particulate Matter - Soot Blowing and Load Change (effective 01/01/04 through 5/31/06 for Unit 001, and 01/01/04 through 10/31/05 for Unit 002). Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

A.7.2. Particulate Matter -- Soot Blowing and Load Change (effective 6/01/06 for Unit 001, and 11/01/05 for Unit 002). Particulate matter emissions shall not exceed an average of 0.1 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[0110036-005-AC, Specific Condition A.19.]

A.8. Sulfur Dioxide. Sulfur dioxide emissions shall not exceed 2.75 pounds per million Btu heat input, as measured by applicable compliance methods. Compliance shall be based on the total heat input from all liquid and gaseous fuels burned. The sulfur dioxide emission limitation shall apply at all times including startup, shutdown, and load change. See Specific Condition **A.11.**
[Rules 62-213.440 and 62-296.405(1)(c)1.j., F.A.C.]

A.9. Nitrogen Oxides. Nitrogen oxides emissions shall not exceed 0.20 pounds per million Btu while firing natural gas, and 0.36 pounds per million Btu while firing oil. Compliance shall be demonstrated based on a 30-day rolling average as measured by a continuous emissions monitoring system (CEMS). The CEMS must meet the performance specifications contained in 40 CFR 60, Appendix B, or 40 CFR 75.
[Rules 62-296.570(4)(a)4. and (4)(b)1., F.A.C.]

Monitoring of Operations

A.10. Annual Tests Required, PM and VE. Except as provided in specific conditions **D.6** and **D.7** of this permit, emission testing for particulate emissions and visible emissions shall be performed annually, no later than September 30th of each year, except for units that are not operating because of scheduled maintenance outages and emergency repairs, which will be tested within thirty days of returning to service.
[Rules 62-4.070(3) and 62-213.440, F.A.C.]

A.11. Sulfur Dioxide. The owner or operator of the emission units shall demonstrate compliance with the sulfur dioxide limit of specific condition **A.8** of this permit by the following:

a. Through the use of a continuous emission monitoring system (CEMS) installed, calibrated, operated and maintained in accordance with the quality assurance requirements of 40 CFR 75, adopted and incorporated by reference in Rule 62-204.800,

F.A.C. A Relative Accuracy Test Audit of the SO_2 CEMS shall be conducted no less than annually. Compliance shall be demonstrated based on a 3-hour rolling average.

b. In the event the CEMS becomes temporarily inoperable or interrupted, the fuels and the maximum fuel oil to natural gas firing ratio that shall be used is limited to that which was last used to demonstrate compliance prior to the loss of the CEMS, or the emissions units shall fuel switch and be fired with a fuel oil containing a maximum sulfur content of 2.5%, by weight, or less.

c. When burning 100% fuel oil, the emissions units shall be fired with a fuel oil containing a maximum sulfur content of 2.5%, by weight, or less.

[Rules 62-213.440, 62-204.800 and 62-296.405(1)(c)3., F.A.C.]

Test Methods and Procedures

A.12. Testing While Injecting Additives. The owner or operator shall conduct emission tests while injecting additives consistent with normal operating practices.
[Rule 62-213.440, F.A.C., applicant agreement with EPA on March 3, 1998]

A.13. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17. Particulate testing shall be conducted in accordance with the requirements of specific conditions **D.14** and **A.15** of this permit.
[Rules 62-213.440, 62-296.405(1)(e)2., and 62-297.401, F.A.C.]

A.14. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, **the permittee shall demonstrate compliance using CEMS for sulfur dioxide. See specific condition A.11 of this permit.**
[Rules 62-213.440 and 62-296.405(1)(c)3. and (1)(e)3., F.A.C.]

A.15. Operating Conditions During Testing - PM and VE. Compliance testing during sootblowing and steady-state operation for particulate matter and visible emissions shall be conducted at least once annually, if liquid fuel is fired for more than 400 hours. A visible emissions test shall be conducted during one run of each particulate matter test. Testing shall be conducted as follows:

a. When Burning 100% Fuel Oil. Particulate matter and visible emissions tests during sootblowing and steady-state operation shall be performed on such emissions unit while firing solely fuel oil of less than or equal to 2.5% sulfur by weight (stoichiometrically representative of sulfur dioxide emissions of the SO_2 emission limit of 2.75 lb/mmBtu), except that such test shall not be required to be performed during any year that testing is performed in accordance with specific condition **A.15.b.**

b. When Burning Fuel Oil While Co-firing With Natural Gas. Particulate matter and visible emissions tests during sootblowing and steady-state operation shall be performed on such

emissions unit while co-firing oil with the appropriate proportion of natural gas required to maintain SO_2 emissions below the emission limit of 2.75 lb/mmBtu heat input.
Test Required if Target SO_2 Emission Rate Increased. Following successful completion of such PM and VE testing, further PM and VE testing shall not be required during the next 12 months unless fuel oil is fired that contains greater than 0.20% sulfur above the percentage sulfur concentration fired during the most recent co-firing test. If fuel oil is co-fired containing greater than 0.20% sulfur above the percentage sulfur concentration fired during the most recent co-firing test, additional PM and VE tests shall be performed as described above as soon as practicable, but in no event more than 60 days after firing such higher sulfur fuel oil.
[Rules 62-4.070(3), 62-213.440, 62-296.405(1)(c)3. and 62-297.310(7)(a)9., F.A.C., Request of applicant; Administrative Correction 0110036-002-AV.]

Compliance Assurance Monitoring (CAM) Requirements

A.15.1. Following the construction and installation of the ESPs at the facility, these emissions units will be subject to Compliance Assurance Monitoring (CAM) for those control devices. Therefore, six months following the completion of construction the permittee shall request a revision to this permit to include the requirements for the proposed CAM plan.
[40 CFR 64; and Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

Recordkeeping and Reporting Requirements

A.16. Fuel Records. The owner or operator shall create and maintain for each emission unit hourly records of the amount of each fuel fired, the ratio of fuel oil to natural gas if co-fired, and the heating value and sulfur content of each fuel fired. These records must be of sufficient detail to identify the testing requirements of Specific Condition **A.15.**, and, when applicable, demonstrate compliance with the requirements of Specific Condition **A.11.**, paragraphs b and c, of this permit. Fuel oil heating value and sulfur content shall be determined by taking a daily sample of the fuel fired, combining those samples into a monthly composite, and analyzing a representative sample of the composite. Analysis for sulfur content shall be performed using one of ASTM D2622-94, ASTM D4294-90(95), ASTM D1552-95, ASTM D1266-91, both ASTM D4057-88 and ASTM D129-95, or the latest edition(s). Comparison of the as-fired fuel oil sulfur content shall be made and recorded monthly upon receipt of each monthly composite analysis.
[Rules 62-4.070(3), 62-213.410, 62-213.440 and 62-296.405(1)(c)3., F.A.C.]

A.17. COMS for Periodic Monitoring. The owner or operator is required to install continuous opacity monitoring systems (COMS) pursuant to 40 CFR Part 75. The owner or operator shall maintain and operate COMS and shall make and maintain records of opacity measured by the COMS, for purposes of periodic monitoring.
[Rule 62-213.440, F.A.C., and applicant agreement with EPA on March 3, 1998]

Other Conditions

A.18. These emissions units are also subject to Specific Conditions **D.1.** through **D.20.**, contained in **Subsection D., Common Conditions.**

Subsection B. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
003	Fossil Fuel Steam Generator, Unit 3
004	Fossil Fuel Steam Generator, Unit 4

Fossil fuel fired steam generators Unit 3 and Unit 4 are each 402 MW (electric) steam generators. The emissions units are fired on a variable combination of No. 6 fuel oil, No. 2 fuel oil, natural gas, propane, and on-specification used oil from FPL operations. When firing fuel oil, the maximum heat input for each boiler is 4000 mmBtu per hour, and when firing natural gas or propane, the maximum heat input for each boiler is 4180 mmBtu per hour. Each emissions unit consists of a boiler which drives a turbine generator. Emissions are controlled with low NOx burners and multiple cyclones for particulate matter (for the period 1/01/04 through 10/31/07 for Unit 003, and period 1/01/04 through 5/31/07 for Unit 004). Electrostatic precipitators shall replace the multiple cyclones beyond these dates. Each unit is equipped with a 344-foot stack. *Following the construction and installation of the ESPs at the facility, these emissions units will be subject to Compliance Assurance Monitoring (CAM) for those control devices. See Specific Condition* ***B.15.1.***

{Permitting note(s): These emissions units are regulated under Acid Rain, Phase II; and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator Unit 3 began commercial operation in 1965, and fossil fuel fired steam generator Unit 4 began commercial operation in 1964. These emissions units may inject additives such as magnesium hydroxide and related compounds into each boiler.}

The following specific conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	mmBtu/hr Heat Input*	Fuel Type
3	4180 4000	Natural Gas, Propane No. 2 or 6 Fuel Oil
4	4180 4000	Natural Gas, Propane No. 2 or 6 Fuel Oil

*When a blend of fuel oil and natural gas or propane is burned, the heat input is prorated based upon the percent heat input of each fuel.
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

B.2. Emissions Unit Operating Rate Limitation After Testing. Emissions units may be limited to the operating rate or conditions tested. See Specific Conditions **D.14.** and **B.15.** of this permit.
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation. Fuels. The only fuels allowed to be burned are any combination of No. 6 fuel oil, No. 2 fuel oil, natural gas, propane, and on-specification used oil from FPL operations.
[Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **B.4.1.** through **B.9.** are based on the specified averaging time of the applicable test method.}

B.4.1. Visible Emissions – Steady State Operation (effective 01/01/04 through 10/31/07 for Unit 003, and 01/01/04 through 05/31/07 for Unit 004). Visible emissions shall not exceed 40 percent opacity. Emissions units governed by this visible emissions standard shall conduct a compliance test for visible emissions annually using EPA Reference Method 9.
[Rule 62-296.405(1)(a), F.A.C.; and OGC Case No. 83-0577 & 83-0576, Order dated April 24, 1984.]

B.4.2. Visible Emissions – Steady State Operation (effective 11/01/07 for Unit 003, and 06/01/07 for Unit 004). Visible emissions shall not exceed 20 percent opacity. Emissions units governed by this visible emissions standard shall conduct a compliance test for visible emissions annually using EPA Reference Method 9.
[0110036-005-AC, Specific Condition A.16.]

B.5.1. Visible Emissions – Soot Blowing and Load Change (effective 01/01/04 through 10/31/07 for Unit 003, and 01/01/04 through 05/31/07 for Unit 004). Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition.

Note: these units have operational continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.]

B.5.2. Visible Emissions – Soot Blowing and Load Change (effective 11/01/07 for Unit 003, and 06/01/07 for Unit 004). Visible emissions shall not exceed 40 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 40 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition.

Note: these units have operational continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.; and 0110036-005-AC, Specific Condition A.17.]

B.6.1. Particulate Matter – Steady State Operation (effective 01/01/04 through 10/31/07 for Unit 003, and 01/01/04 through 05/31/07 for Unit 004). Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

B.6.2. Particulate Matter – Steady State Operation (effective 11/01/07 for Unit 003, and 06/01/07 for Unit 004). Particulate matter emissions shall not exceed 0.03 pound per million Btu heat input, as measured by applicable compliance methods.
[0110036-005-AC, Specific Condition A.18.]

B.7.1. Particulate Matter – Soot Blowing and Load Change (effective 01/01/04 through 10/31/07 for Unit 003, and 01/01/04 through 05/31/07 for Unit 004). Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

B.7.2. Particulate Matter – Soot Blowing and Load Change (effective 11/01/07 for Unit 003, and 06/01/07 for Unit 004). Particulate matter emissions shall not exceed an average of 0.1 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[0110036-005-AC, Specific Condition A.19.]

B.8. Sulfur Dioxide. Sulfur dioxide emissions shall not exceed 2.75 pounds per million Btu heat input, as measured by applicable compliance methods. Compliance shall be based on the total heat input from all liquid and gaseous fuels burned. The sulfur dioxide emission limitation shall apply at all times including startup, shutdown, and load change. See Specific Condition **B.11.**
[Rules 62-213.440 and 62-296.405(1)(c)1.j., F.A.C.]

B.9. Nitrogen Oxides. Nitrogen oxides emissions shall not exceed 0.40 pounds per million Btu while firing natural gas, and 0.53 pounds per million Btu while firing oil. Compliance shall be demonstrated based on a 30-day rolling average as measured by a CEMS. The CEMS must meet the performance specifications contained in 40 CFR 60, Appendix B, or 40 CFR 75.
[Rules 62-296.570(4)(a)4. and (4)(b)2., F.A.C.]

Monitoring of Operations

B.10. Annual Tests Required, PM and VE. Except as provided in Specific Conditions **D.6.** and **D.7.** of this permit, emission testing for particulate emissions and visible emissions shall be performed annually, no later than September 30th of each year, except for units that are not operating because of scheduled maintenance outages and emergency repairs, which will be tested within thirty days of returning to service.
[Rules 62-4.070(3) and 62-213.440, F.A.C.]

B.11. Sulfur Dioxide. The owner or operator of the emission units shall demonstrate compliance with the sulfur dioxide limit of Specific Condition **B.8.** of this permit by the following:

a. Through the use of a continuous emission monitoring system (CEMS) installed, calibrated, operated and maintained in accordance with the quality assurance requirements of 40 CFR 75, adopted and incorporated by reference in Rule 62-204.800,

F.A.C. A Relative Accuracy Test Audit of the SO_2 CEMS shall be conducted no less than annually. Compliance shall be demonstrated based on a 3-hour rolling average.

b. In the event the CEMS becomes temporarily inoperable or interrupted, the fuels and the maximum fuel oil to natural gas firing ratio that shall be used is limited to that which was last used to demonstrate compliance prior to the loss of the CEMS, or the emissions units shall fuel switch and be fired with a fuel oil containing a maximum sulfur content of 2.5%, by weight, or less.

c. When burning 100% fuel oil, the emissions units shall be fired with a fuel oil containing a maximum sulfur content of 2.5%, by weight, or less.

[Rules 62-213.440, 62-204.800 and 62-296.405(1)(c)3., F.A.C.]

Test Methods and Procedures

B.12. Testing While Injecting Additives. The owner or operator shall conduct emission tests while injecting additives consistent with normal operating practices.
[Rule 62-213.440, F.A.C., applicant agreement with EPA on March 3, 1998]

B.13. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17. Particulate testing shall be conducted in accordance with the requirements of specific conditions **D.14** and **B.15** of this permit.
[Rules 62-213.440, 62-296.405(1)(e)2., and 62-297.401, F.A.C.]

B.14. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, **the permittee shall demonstrate compliance using CEMS for sulfur dioxide. See specific condition B.11 of this permit.**
[Rules 62-213.440 and 62-296.405(1)(c)3. and (1)(e)3., F.A.C.]

B.15. Operating Conditions During Testing - PM and VE. Compliance testing during sootblowing and steady-state operation for particulate matter and visible emissions shall be conducted at least once annually, if liquid fuel is fired for more than 400 hours. A visible emissions test shall be conducted during one run of each particulate matter test. Testing shall be conducted as follows:

a. When Burning 100% Fuel Oil. Particulate matter and visible emissions tests during sootblowing and steady-state operation shall be performed on such emissions unit while firing solely fuel oil of less than or equal to 2.5% sulfur by weight (stoichiometrically representative of sulfur dioxide emissions of the SO_2 emission limit of 2.75 lb/mmBtu), except that such test shall not be required to be performed during any year that testing is performed in accordance with specific condition **B.15.b.**

b. When Burning Fuel Oil While Co-firing With Natural Gas. Particulate matter and visible emissions tests during sootblowing and steady-state operation shall be performed on such emissions unit while co-firing oil with the appropriate proportion of natural gas required to maintain SO_2 emissions below the emission limit of 2.75 lb/mmBtu heat input.
Test Required if Target SO_2 Emission Rate Increased. Following successful completion of such PM and VE testing, further PM and VE testing shall not be required during the next 12 months unless fuel oil is fired that contains greater than 0.20% sulfur above the percentage sulfur concentration fired during the most recent co-firing test. If fuel oil is co-fired containing greater than 0.20% sulfur above the percentage sulfur concentration fired during the most recent co-firing test, additional PM and VE tests shall be performed as described above as soon as practicable, but in no event more than 60 days after firing such higher sulfur fuel oil.
[Rules 62-4.070(3), 62-213.440, 62-296.405(1)(c)3. and 62-297.310(7)(a)9., F.A.C., Request of applicant; Administrative Correction 0110036-002-AV.]

Compliance Assurance Monitoring (CAM) Requirements

B.15.1. Following the construction and installation of the ESPs at the facility, these emissions units will be subject to Compliance Assurance Monitoring (CAM) for those control devices. Therefore, six months following the completion of construction the permittee shall request a revision to this permit to include the requirements for the proposed CAM plan.
[40 CFR 64; and Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

Recordkeeping and Reporting Requirements

B.16. Fuel Records. The owner or operator shall create and maintain for each emission unit hourly records of the amount of each fuel fired, the ratio of fuel oil to natural gas if co-fired, and the heating value and sulfur content of each fuel fired. These records must be of sufficient detail to identify the testing requirements of specific condition **B.15**, and, when applicable, demonstrate compliance with the requirements of condition **B.11**, paragraphs b and c, of this permit. Fuel oil heating value and sulfur content shall be determined by taking a daily sample of the fuel fired, combining those samples into a monthly composite, and analyzing a representative sample of the composite. Analysis for sulfur content shall be performed using one of ASTM D2622-94, ASTM D4294-90(95), ASTM D1552-95, ASTM D1266-91, both ASTM D4057-88 and ASTM D129-95, or the latest edition(s). Comparison of the as-fired fuel oil sulfur content shall be made and recorded monthly upon receipt of each monthly composite analysis.
[Rules 62-4.070(3), 62-213.410, 62-213.440 and 62-296.405(1)(c)3., F.A.C.]

B.17. COMS for Periodic Monitoring. The owner or operator is required to install continuous opacity monitoring systems (COMS) pursuant to 40 CFR Part 75. The owner or operator shall maintain and operate COMS and shall make and maintain records of opacity measured by the COMS, for purposes of periodic monitoring.
[Rule 62-213.440, F.A.C., and applicant agreement with EPA on March 3, 1998]

Other Conditions

B.18. These emissions units are also subject to Specific Conditions **D.1.** through **D.20.**, contained in **Subsection D., Common Conditions.**

Subsection C. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
005	12 Simple Cycle Gas Turbines, GT1 through GT12

Emissions unit 005 consists of 12 simple cycle gas turbines (GT1 through GT12) manufactured by Pratt & Whitney, with a total capacity rated at 504 MW, 8424 mmBtu/hr. The emissions units are fired on any combination of No. 2 fuel oil and natural gas. Each turbine unit consists of two turbine engines which drive a turbine generator. Emissions are uncontrolled. Each unit is equipped with a 44-foot stack. The turbines are regulated collectively as one emission unit.

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. These emissions units are *not subject* to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. All turbines began commercial operation in 1971.}

The following specific conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity. *The maximum operation heat input rates are as follows:*

Unit No.	mmBtu/hr Heat Input*	Fuel Type
GT1 through GT12	8424	Natural Gas
	8424	No. 2 Fuel Oil

*Total heat input for all twelve combustion turbines.
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to *100 percent of the unit's rated capacity* (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

C.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **D.14.** of this permit.
[Rule 62-297.310(2), F.A.C.]

C.3. Methods of Operation. Fuels. *The only fuels allowed to be burned are any combination* of No. 2 fuel oil and natural gas.
[Rule 62-213.410, F.A.C.]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **C.4.** and **C.5.** are based on the specified averaging time of the applicable test method.}

C.4. Visible Emissions. Visible emissions from each turbine shall not be equal to or greater *than 20 percent opacity.*
[Rule 62-296.320(4)(b)1., F.A.C.]

C.5. Nitrogen Oxides. Nitrogen oxides emissions shall not exceed 0.50 pounds per million Btu while firing natural gas, and 0.90 pounds per million Btu while firing oil.
[Rules 62-296.570(4)(b)5., F.A.C.]

Monitoring of Operations

C.6. Visible Emissions Testing Required. The owner or operator shall conduct testing for visible emissions, using EPA Method 9, while the combustion turbine is operating at 90-100 percent of its capacity, according to the following schedule.

The owner or operator shall conduct testing for visible emissions while firing fuel oil for each simple-cycle turbine unit upon that turbine's exceeding 400 hours of operation on fuel oil, and every 150 hours of operation on fuel oil thereafter, in any given federal fiscal year (October 1 through September 30). Such tests shall be performed within 15 days of exceeding such operating hours, to allow for prior notification of the tests.
[Rule 62-213.440, F.A.C.; applicant agreement with EPA on March 3, 1998; and AO 06-230618.]

C.7. Nitrogen Oxides. Provided operation is no more than 320 hours/year/turbine on oil, NOx emissions for the combustion turbines shall be tested every five (5) years by EPA Method 20 tests as described in 40 CFR 60, Appendix A (July 1, 1996) on any representative unit in the bank of the combustion turbines. Tests shall be conducted both while burning 100% natural gas and 100% light distillate oil.
[Rule 62-296.570, F.A.C.; and requested by the applicant in a letter dated September 19, 2000.]

Test Methods and Procedures

C.8. Nitrogen Oxides. The test method for nitrogen oxides emissions shall be EPA Method 20, or EPA Method 7E, incorporated by reference in Chapter 62-297, F.A.C. If the owner or operator obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall automatically become a condition of this permit.
[Rules 62-213.440, 62-296.570(4)(a)3., 62-297.401, F.A.C.; and applicant request.]

Recordkeeping and Reporting Requirements

C.9. Records of Fuel Consumption and Operating Time Required. The owner or operator shall make and maintain records of the hours of operation of each turbine and the total fuel oil consumption of all twelve turbines in sufficient detail to ensure compliance with Specific Condition **C.6.** of this permit.
[Rule 62-4.070(3), F.A.C.]

Other Conditions

C.10. These emissions units are also subject to Specific Conditions **D.1.** through **D.19.**, contained in **Subsection D., Common Conditions.** Specific Condition **D.20.** is not applicable to these emission units.

Subsection D. Common Conditions.

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1.
002	Fossil Fuel Steam Generator, Unit 2.
003	Fossil Fuel Steam Generator, Unit 3.
004	Fossil Fuel Steam Generator, Unit 4.
005	12 Simple Cycle Gas Turbines, GT1 through GT12.

The following conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

D.1. Hours of Operation. The emissions units may operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

Excess Emissions

D.2. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

D.3. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

D.4. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

D.5. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

D.6. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
    a. Did not operate; or
    b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
    a. Visible emissions, if there is an applicable standard;
    b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 100 tons per year or more of any other regulated air pollutant; and
    c. Each NESHAP pollutant, if there is an applicable emission standard.
5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant

emissions from the emissions unit and to provide a report on the results of said tests to the Department.
(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C., SIP Approved]

D.7. When PM Tests Not Required. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

D.8. When VE Tests Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rule 62-4.070(3), F.A.C.]

Test Methods and Procedures

{Permitting Note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.9. Visible Emissions - Turbines. The test method for visible emissions for emissions unit 005 (bank of twelve combustion turbines) shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800 and 62-297.401, F.A.C.]

D.10. Visible Emissions - Boilers, Units 1, 2, 3 and 4. The test method for visible emissions for emissions units 001 (Unit 1), 002 (Unit 2), 003 (Unit 3) and 004 (Unit 4) shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. See Specific Condition **D.11**.
[Rules 62-296.405(1)(e)1. and 62-297.401, F.A.C.]

D.11. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:
1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rule 62-297.401, F.A.C.]

D.12. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

D.13. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

D.14. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

D.15. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

D.16. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

Recordkeeping and Reporting Requirements

D.17. Malfunctions - Notification. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Broward County Department of Planning and Environmental Protection, Air Quality Division, in accordance with Rule 62-4.130, F.A.C. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its 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 Department rules. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Broward County Department of Planning and Environmental Protection, Air Quality Division.
[Rule 62-210.700(6), F.A.C.]

D.18. Excess Emissions - Report. Submit to the Broward County Department of Planning and Environmental Protection, Air Quality Division, a written report of emissions in excess of emission limiting standards as set forth in this permit, for each calendar quarter. The nature and

cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

D.19. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Broward County Department of Planning and Environmental Protection, Air Quality Division, on the results of each such test.
(b) The required test report shall be filed with the Broward County Department of Planning and Environmental Protection, Air Quality Division, as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Broward County Department of Planning and Environmental Protection, Air Quality Division, to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.

21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

D.20. Used Oil. Burning of on-specification used oil is allowed in emissions units 001, 002, 003 and 004 in accordance with all other conditions of this permit and the following additional conditions:

a. On-specification Used Oil Allowed as Fuel: This permit allows the burning of used oil fuel meeting EPA "on-specification" used oil specifications, with a PCB concentration of less than 50 ppm, originating from FPL operations. Used oil that does not meet the specifications for on-specification used oil shall not be burned at this facility.

On-specification used oil shall meet the following specifications: [40 CFR 279, Subpart B.]

Arsenic shall not exceed 5.0 ppm;
Cadmium shall not exceed 2.0 ppm;
Chromium shall not exceed 10.0 ppm;
Lead shall not exceed 100.0 ppm;
Total halogens shall not exceed 1000 ppm;
Flash point shall not be less than 100 degrees F.

b. Quantity Limited: The maximum total quantity of used oil that may be burned in all four emissions units is 1.5 million gallons in any consecutive 12-month period.

c. Used Oil Containing PCBs Not Allowed: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. PCB Concentration of 2 to less than 50 ppm: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Required: The owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point, and PCBs.

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods), latest edition.

f. Record Keeping Required: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department: [40 CFR 279.61 and 761.20(e)]

(1) The gallons of on-specification used oil received and burned each month. (This record shall be completed no later than the fifteenth day of the succeeding month.)
(2) The total gallons of on-specification used oil burned in the preceding consecutive 12-month period. (This record shall be completed no later than the fifteenth day of the succeeding month.)
(3) Results of the analyses required above.

g. Reporting Required: The owner or operator shall submit, with the Annual Operation Report form, the analytical results and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761, unless otherwise noted]

Section IV. This Section is the Acid Rain Part.

Operated by: Florida Power and Light Company
ORIS code: **0617**

Subsection A. This Subsection addresses Acid Rain, Phase II.

The emissions unit(s) listed below are regulated under Phase II of the federal Acid Rain Program.

E.U. ID No.	EPA ID No.	Brief Description
001	PPE1	Fossil Fuel Steam Generator, Unit 1
002	PPE2	Fossil Fuel Steam Generator, Unit 2
003	PPE3	Fossil Fuel Steam Generator, Unit 3
004	PPE4	Fossil Fuel Steam Generator, Unit 4

1. The Phase II part application renewal submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application renewal listed below:

a. DEP Form No. 62-210.900(1)(a), effective 04/16/01, and signed by the Designated Representative on 04/07/03.

[Chapter 62-213, F.A.C.; and Rule 62-214.320, F.A.C.]

2. Sulfur dioxide (SO_2) allowance allocations for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2004	2005	2006	2007	2008
001	PPE1	SO2 allowances, under Table 2 of 40 CFR Part 73	2339*	2339*	2339*	2339*	2339*
002	PPE2	SO2 allowances, under Table 2 of 40 CFR Part 73	2413*	2413*	2413*	2413*	2413*
003	PPE3	SO2 allowances, under Table 2 of 40 CFR Part 73	5880*	5880*	5880*	5880*	5880*

E.U. ID No.	EPA ID	Year	2004	2005	2006	2007	2008
004	PPE4	SO2 allowances, under Table 2 of 40 CFR Part 73	5962*	5962*	5962*	5962*	5962*

* The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2 of 40 CFR 73.

3. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62- 214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, Fast-Track Revisions of Acid Rain Parts.
[Rule 62-213.413, F.A.C.]

4. Comments, notes, and justifications. The Phase II Part Application Renewal form was received on April 24, 2003.

5. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.

b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.
[Rule 62-213.440(1)(c)1., 2. & 3., F.A.C.]

6. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year.
{See condition No. 51., Appendix TV-4, Title V Conditions.}
[Rule 62-214.420(11), F.A.C.]

7. Where an applicable requirement of the Act is more stringent than applicable regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, F.A.C., Definitions – Applicable Requirements.]

Appendix I-1, List of Insignificant Emissions Units and/or Activities

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)1., F.A.C., Generic Emissions Unit Exemption, are exempt from the permitting requirements of Chapters 62-210, 62-212 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities
1. Spent boiler chemical cleaning liquid evaporation.
2. Laboratory equipment used exclusively for chemical or physical analysis.
3. Brazing, soldering, or welding equipment.
4. Surface coating facilities provided that 6.0 gallons of coatings per day or less are applied.
5. Hydrazine feed line vent.
6. Lube oil system.
7. Oil/water separators and related equipment.
8. Misc. mobile vehicle operation.
9. Paint & lube oil building.
10. Chemical storage building.
11. Hazardous waste storage area.
12. Natural gas metering station.
13. Internal combustion engine.
14. Fire and safety equipment.

Appendix H-1, Permit History/ID Number Changes

Permit History (for tracking purposes):

E.U. ID No.	Description	Permit No.	Issue Date	Expiration Date	Extended Date[1, 2]	Revised Date(s)
001	Fossil Fuel Steam Generator #1	AO 06-223345	04/21/93	02/28/98		
002	Fossil Fuel Steam Generator #2	AO 06-223350	04/21/93	02/15/98		
003	Fossil Fuel Steam Generator #3	AO 06-223351	04/21/93	02/15/98		
004	Fossil Fuel Steam Generator #4	AO 06-223352	04/21/93	02/15/98		
005	Gas Turbine Generator #1 - 12	AO 06-230618	06/16/93	06/04/98		
001-005	As noted above.	0110036-001-AV 0110036-002-AV (Administrative Correction) 0110036-003-AV	06/24/98 02/26/01	12/31/03 12/31/03 12/31/03		
001-004	As noted above.	0110036-005-AC	07/14/03	04/01/07		

ID Number Changes (for tracking purposes):

From: **Facility ID No.:** 50BRO060036

To: **Facility ID No.:** 0110036

Notes:
1 - AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
2 - AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.
{Rule 62-213.420(1)(b)2., F.A.C., allows Title V Sources to operate under existing valid permits that were in effect at the time of application until the Title V permit becomes effective.}

Appendix U-1, List of Unregulated Emissions Units and/or Activities

Unregulated Emissions Units and/or Activities. An emissions unit which emits no "emissions-limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

The below listed emissions units and/or activities are neither 'regulated emissions units' nor 'insignificant emissions units'.

E.U. ID No.	Brief Description of Emissions Units and/or Activity
017	Above ground fuel oil storage tanks
018	Miscellaneous internal combustion engines and portable equipment

Table 1-1, Summary of Air Pollutant Emission Standards

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

			Allowable Emissions			Equivalent Emissions[1,2]			
Pollutant	Fuel(s)	Hours per Year	Standard(s)	lb/hour	TPY	lb/hour	TPY	Regulatory Citations	See Permit Condition(s)
VE Steady State	Oil, Natural Gas or Propane	8760	40% opacity, or 20% opacity (see Specific Condition **A.4.2.**)					Rule 62-296.405(1)(a), F.A.C.	**A.4.**
VE Soot Blowing or Load Change	Oil, Natural Gas or Propane	8760	60 % opacity (>60% opacity for not more than 4, six-minute periods), or 40 % opacity (>40% opacity for not more than 4, six-minute periods) (see Specific Condition **A.5.2.**)					Rule 62-210.700(3), F.A.C.	**A.5.**
PM Steady State	Oil, Natural Gas or Propane	8760	0.1 lb/mmBtu, or 0.03 lb/mmBtu (see Specific condition **A.6.2.**)			230, or 69		Rule 62-296.405(1)(b), F.A.C.	**A.6.1.**, or **A.6.2.**
PM Soot Blowing or Load Change	Oil, Natural Gas or Propane	8760	0.3 lb/mmBtu, or 0.1 lb/mmBtu (see Specific condition **A.7.2.**)			690, or 230		Rule 62-210.700(3), F.A.C.	**A.7.1.**, or **A.7.2.**

Table 1-1, Continued

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

			Allowable Emissions			Equivalent Emissions[1,2]			
Pollutant	Fuel(s)	Hours per Year	Standard(s)	lb/hour	TPY	lb/hour	TPY	Regulatory Citations	See Permit Condition(s)
SO_2	Oil, Natural Gas	8760	2.75 lb/mmBtu			**6325***	**27704***	Rule 62-296.405(1)(c)1.j., F.A.C.	**A.8.**
NO_x	Oil	8760	0.36 lb/mmBtu			**828**	**3626.6**	Rule 62-296.570(4)(b)1, F.A.C.	**A.9.**
NO_x	Natural Gas	8760	0.20 lb/mmBtu			**480**	**2102.4**	Rule 62-296.570(4)(b)1, F.A.C.	**A.9.**

Table 1-1, Continued

Emissions Unit	Brief Description
003	Fossil Fuel Steam Generator, Unit 3
004	Fossil Fuel Steam Generator, Unit 4

			Allowable Emissions			Equivalent Emissions[1,2]			
Pollutant	Fuel(s)	Hours per Year	Standard(s)	lb/hour	TPY	lb/hour	TPY	Regulatory Citations	See Permit Condition(s)
VE Steady State	Oil, Natural Gas or Propane	8760	40% opacity, or 20% opacity (see Specific Condition **B.4.2.**)					Rule 62-296.405(1)(a), F.A.C.	**B.4.**
VE Soot Blowing or Load Change	Oil, Natural Gas or Propane	8760	60 % opacity (>60% opacity for not more than 4, six-minute periods), or 40 % opacity (>40% opacity for not more than 4, six-minute periods) (see Specific Condition **B.5.2.**)					Rule 62-210.700(3), F.A.C.	**B.5.**
PM Steady State	Oil, Natural Gas or Propane	8760	0.1 lb/mmBtu, or 0.03 lb/mmBtu (see Specific Condition **B.6.2.**)			400, or 120		Rule 62-296.405(1)(b), F.A.C.	**B.6.1.**, or **B.6.2.**
PM Soot Blowing or Load Change	Oil, Natural Gas or Propane	8760	0.3 lb/mmBtu, or 0.1 lb/mmBtu (see Specific Condtion **B.7.2.**)			1200, or 400		Rule 62-210.700(3), F.A.C.	**B.7.1.**, or **B.7.2.**

Table 1-1, Continued

Emissions Unit	Brief Description
003	Fossil Fuel Steam Generator, Unit 3
004	Fossil Fuel Steam Generator, Unit 4

			Allowable Emissions			Equivalent Emissions[1,2]			
Pollutant	Fuel(s)	Hours per Year	Standard(s)	lb/hour	TPY	lb/hour	TPY	Regulatory Citations	See Permit Condition(s)
SO_2	Oil, Natural Gas	8760	2.75 lb/mmBtu			11000*	48180*	Rule 62-296.405(1)(c)1.j., F.A.C.	**B.8.**
NO_x	Oil	8760	0.53 lb/mmBtu			2120	9285.6	Rules 62-296.570(4)(b)2, F.A.C.	**B.9.**
NO_x	Natural Gas	8760	0.40 lb/mmBtu			1672	7323.4	Rule 62-296.570(4)(b)2, F.A.C.	**B.9.**

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Table 1-1, Continued

Emissions Unit	Brief Description
005	12 Simple Cycle Gas Turbines, GT1 through GT12.

			Allowable Emissions			Equivalent Emissions[1,3]			
Pollutant	Fuel(s)	Hours per Year	Standard(s)	lb/hour	TPY	lb/hour	TPY	Regulatory Citations	See Permit Condition(s)
VE Steady State	Oil, Natural Gas or Propane	8760	20% opacity					Rule 62-296.320(4)(b)1., F.A.C.	**C.4.**
NO_x	Oil	8760	0.90 lb/mmBtu			7581.6	33207	Rule 62-296.570(4)(b)2, F.A.C.	**C.5.**
NO_x	Natural Gas	8760	0.50 lb/mmBtu			4212	18449	Rule 62-296.570(4)(b)5, F.A.C.	**C.5.**

Notes:

[1] The "Equivalent Emissions" listed are for informational purposes only.
[2] The "Equivalent Emissions" are for each emission unit, unless otherwise noted.
[3] The "Equivalent Emissions" are for all twelve turbines combined.
*Lb/hr and TPY values are for SO_2 emissions using fuel oil.

Table 2-1, Summary of Compliance Requirements

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
VE	Oil, Natural Gas or Propane	DEP Method 9	Annual	September 30	1 hour	No	**A.10. & A.15.**
PM	Oil, Natural Gas or Propane	EPA Test Methods 5, 5B, or 17	Annual	September 30	3 hours	No	**A.10., A.13. & A.15.**
SO_2	Oil, Natural Gas or Propane	Continuous Emissions Monitor	Continuous			Yes	**A.11. & A.14.**
NOx	Oil, Natural Gas or Propane	Continuous Emissions Monitor	Continuous			Yes	**A.9.**

Table 2-1, Continued

Emissions Unit	Brief Description
003	*Fossil Fuel Steam Generator, Unit 3*
004	Fossil Fuel Steam Generator, Unit 4

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
VE	Oil, Natural Gas or Propane	DEP Method 9	Annual	September 30	1 hour	No	**B.10. & B.15.**
PM	Oil, Natural Gas or Propane	EPA Test Methods 5, 5B, or 17	Annual	September 30	3 hours	No	**B.10., B.13. & B.15.**
SO_2	Oil, Natural Gas or Propane	Continuous Emissions Monitor	Continuous			Yes	**B.11. & B.14.**
NOx	Oil, Natural Gas or Propane	Continuous Emissions Monitor	Continuous			Yes	**B.9.**

Table 2-1, Continued

Emissions Unit	Brief Description
005	12 Simple Cycle Gas Turbines, GT1 through GT12.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
VE	Oil, Natural Gas	EPA Method 9	Annual, each turbine exceeding fuel limit.	October 31	30 min.	No	**C.6.**
NOx	Oil, Natural Gas	EPA Method 20 or EPA Method 7E	Every five years, one turbine only, provided operation is no more than 320 hours/year/ turbine on oil.	September 30	3 hours	No	**C.7., C.8.**

Notes:

[1] Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.
[2] CMS = continuous monitoring system

ADVANTAGES/DISADVANTAGES

PARTICULATE REMOVAL TECHNOLOGIES

RRL-6
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT _____
PAGES 1-2

Advantages and Disadvantages of Particulate Removal Technologies				
Characteristic	**Mechanical Collectors**	*** ESPs**	**Fabric Filters**	**Combustion Controls**
Capability of producing < 5% opacity	No	Yes	Yes	No
Suitable for No. 6 oil-fired boilers	Yes	Yes	No	Yes
Flue gas pressure drop, inwg	4 to 6	1 to 2	-------	NA
Energy demand (other than ID fan)	None	High	-------	High
Capital cost	Lowest	High	-------	Moderate
Operating/Maintenance cost - relative	Low	High	-------	Moderate

* Recommended Technology

Items of note in this table are the mechanical collector's inability to achieve the desired plume opacity and the fabric filter's unsuitability for flue gas generated by No. 6 fuel oil due to the stickiness of the ash and resultant potential for the bags to be "blinded".

ADVANTAGES/DISADVANTAGES

SO_3 REMOVAL TECHNOLOGIES

RRL-7
DOCKET NO. 030007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT _____
PAGES 1-2

Advantages and Disadvantages of SO_3 Removal Technologies				
Characteristic	**Alkaline Reagent Injection**		**Wet ESP**	**** Flue Gas Reheat**
	**** MgO**	**Na_2SO_3 / $NaHSO_3$**		
Capability of producing < 10 ppm SO_3	Yes	Yes	Yes	No
Visible moisture plume produced	No	No	Yes	No – would prevent such plume
Suitable for No. 6 oil-fired boilers	Yes	Yes	Yes	Yes
Flue gas pressure drop, inwg	<1	<1	2 to 4	<1
Energy demand (other than ID fan)	Low	Low	High	Low
Level of development	Demonstrated	Developmental	Demonstrated	Demonstrated
Space requirements – relative	Low	Low	High	Low
Effect on existing stacks	None	None	Corrosion resistant lining required	None
Capital cost - relative	Very Low	Very low	Very high	Low
Operating/Maintenance cost - relative	High	High	High	Low

**Recommended Technology

SDR-1 part of composite exhibit #3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030007-EI EXHIBIT NO. Comp. Ex. 3
COMPANY/ GULF POWER
WITNESS: S.D. Ritenour SDR-1
DATE: 11-18-03

Schedule 1A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

Line		Period Amount ($)
1	End of Period Actual Total True-Up for the Period January 2002 - December 2002 (Schedule 2A, Line 5+6+10)	675,367
2	Estimated/Actual True-Up Amount approved for the period January 2002 - December 2002 (Order NO. PSC-02-1735-FOF-EI)	445,767
3	Final True-Up Amount to be refunded/(recovered) in the projection period January 2004 - December 2004 (Lines 1 - 2)	229,600

Schedule 2A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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)	794,374	693,685	731,839	748,412	883,480	956,279	1,055,437	1,015,039	955,455	848,585	686,684	755,823	10,125,092
2	True-Up Provision (Order No PSC-01-2463-FOF-EI)	110,663	110,663	110,663	110,663	110,663	110,663	110,663	110,663	110,663	110,663	110,663	110,667	1,327,960
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	905,037	804,348	842,502	859,075	994,143	1,066,942	1,166,100	1,125,702	1,066,118	959,248	797,347	866,490	11,453,052
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5A, Line 9)	107,862	692,063	71,399	121,077	247,821	159,833	124,536	105,684	64,874	301,437	145,560	399,040	2,541,186
	b Capital Investment Projects (Schedule 7A, Line 9)	676,997	675,670	674,831	676,997	682,061	698,069	700,326	697,753	696,045	695,570	693,181	690,486	8,257,986
	c **Total Jurisdictional ECRC Costs**	784,859	1,367,733	746,230	798,074	929,882	857,902	824,862	803,437	760,919	997,007	838,741	1,089,526	10,799,172
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	120,178	(563,385)	96,272	61,001	64,261	209,040	341,238	322,265	305,199	(37,759)	(41,394)	(223,036)	653,880
6	Interest Provision (Schedule 3A, Line 10)	2,253	1,750	1,258	1,213	1,134	1,174	1,400	1,703	2,014	2,015	1,561	1,110	18,585
7	Beginning Balance True-Up & Interest Provision	1,327,960	1,342,630	670,332	657,199	608,750	563,482	663,033	895,008	1,108,313	1,304,863	1,158,456	1,007,960	1,327,960
	a Deferred True-Up from January 2000 - December 2000 (Order No. PSC-02-1735-FOF-EI)	187,480	187,480	187,480	187,480	187,480	187,480	187,480	187,480	187,480	187,480	187,480	187,480	187,480
8	True-Up Collected/(Refunded) (see Line 2)	(110,663)	(110,663)	(110,663)	(110,663)	(110,663)	(110,663)	(110,663)	(110,663)	(110,663)	(110,663)	(110,663)	(110,667)	(1,327,960)
9	End of Period Total True-Up (Lines 5 + 6 + 7 + 7a + 8)	1,527,208	857,812	844,679	796,230	750,962	850,513	1,082,488	1,295,793	1,492,343	1,345,936	1,195,440	862,847	859,945
10	Adjustments to Period Total True-Up Including Interest O&M Changes per Audit *	2,902												2,902
11	**Current Period Total Net True-Up (Lines 9 + 10)**	1,530,110	857,812	844,679	796,230	750,962	850,513	1,082,488	1,295,793	1,492,343	1,345,936	1,195,440	862,847	862,847

** Reduction to General Water Quality in November 2001*

Schedule 3A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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 +7b+ 10)	1,518,342	1,530,110	857,812	844,679	796,230	750,962	850,513	1,082,488	1,295,793	1,492,343	1,345,936	1,195,440	
2 Ending True-Up Amount Before Interest (Line 1 + Schedule 2A, Lines 5 + 8)	1,527,857	856,062	843,421	795,017	749,828	849,339	1,081,088	1,294,090	1,490,329	1,343,921	1,193,879	861,737	
3 Total of Beginning & Ending True-up (Lines 1 + 2)	3,046,199	2,386,172	1,701,233	1,639,696	1,546,058	1,600,301	1,931,601	2,376,578	2,786,122	2,836,264	2,539,815	2,057,177	
4 Average True-Up Amount (Line 3 x 1/2)	1,523,100	1,193,086	850,617	819,848	773,029	800,151	965,801	1,188,289	1,393,061	1,418,132	1,269,908	1,028,589	
5 Interest Rate (First Day of Reporting Business Month)	0 017800	0.017700	0.017500	0 018000	0 017500	0.017700	0.017500	0.017300	0.017100	0.017600	0.016500	0.013000	
6 Interest Rate (First Day of Subsequent Business Month)	0.017700	0.017500	0.018000	0.017500	0.017700	0.017500	0.017300	0.017100	0.017600	0.016500	0 013000	0.012900	
7 Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.035500	0.035200	0.035500	0.035500	0.035200	0.035200	0.034800	0.034400	0.034700	0.034100	0.029500	0.025900	
8 Average Interest Rate (Line 7 x 1/2)	0.017750	0.017600	0.017750	0 017750	0.017600	0.017600	0.017400	0 017200	0 017350	0.017050	0.014750	0.012950	
9 Monthly Average Interest Rate (Line 8 x 1/12)	0.001479	0.001467	0.001479	0.001479	0 001467	0 001467	0.001450	0.001433	0.001446	0.001421	0.001229	0 001079	
10 Interest Provision for the Month (Line 4 x Line 9)	2,253	1,750	1,258	1,213	1,134	1,174	1,400	1,703	2,014	2,015	1,561	1,110	18,585

Schedule 4A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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*	35,819	55,000	(19,181)	(34.9)	%
	.2 Air Emission Fees	739,474	707,206	32,268	4.6	%
	.3 Title V	62,718	77,046	(14,328)	(18.6)	%
	.4 Asbestos Fees	1,520	1,520	0	0.0	%
	.5 Emission Monitoring	480,413	547,402	(66,989)	(12.2)	%
	.6 General Water Quality	233,397	228,352	5,045	2.2	%
	.7 Groundwater Contamination Investigation	834,480	819,967	14,513	1.8	%
	.8 State NPDES Administration	8,105	7,513	592	7.9	%
	.9 Lead and Copper Rule	6,988	18,257	(11,269)	(61.7)	%
	.10 Env Auditing/Assessment	7,457	2,162	5,295	244.9	%
	.11 General Solid & Hazardous Waste	259,211	196,974	62,237	31.6	%
	.12 Above Ground Storage Tanks	31,807	17,396	14,411	82.8	%
	.13 Low Nox	958	0	958	100.0	%
	.14 Ash Pond Diversion Curtains	0	0	0	0.0	%
	.15 Mercury Emissions	0	0	0	0.0	%
	.16 Sodium Injection	50,486	59,586	(9,100)	(15.3)	%
	.17 Gulf Coast Ozone Study	20,349	21,605	(1,256)	(5.8)	%
	.18 SO2 Allowances	(142,324)	(150,136)	7,812	(5.2)	%
2	Total O & M Activities	2,630,858	2,609,850	21,008	0.8	%
3	Recoverable Costs Allocated to Energy	1,247,893	1,317,709	(69,816)	(5.3)	%
4	Recoverable Costs Allocated to Demand	1,382,965	1,292,141	90,824	7.0	%

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-02-1735-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 2002 - December 2002

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	-	1,091	-	-	10,329	(334)	7,054	-	-	5,998	5,525	6,156	35,819		35,819
	.2 Air Emission Fees	-	615,100	-	-	-	-	-	-	-	124,374	-	-	739,474		739,474
	.3 Title V	3,594	4,398	4,620	4,096	2,141	3,061	10,241	4,754	6,251	8,146	5,542	5,874	62,718		62,718
	.4 Asbestos Fees	500	-	-	-	-	-	-	1,000	-	-	-	20	1,520	1,520	
	.5 Emission Monitoring	18,765	18,531	8,514	27,695	27,252	45,756	(8,095)	62,895	36,904	85,325	32,798	124,073	480,413		480,413
	.6 General Water Quality	4,178	14,582	10,971	7,513	17,042	19,214	10,877	26,054	9,998	46,748	39,968	26,252	233,397	233,397	
	.7 Groundwater Contamination Investigation	49,479	46,700	29,121	66,145	160,867	86,276	107,494	18,058	11,984	24,828	13,382	220,146	834,480	834,480	
	.8 State NPDES Administration	-	-	-	-	13	-	250	-	7,574	-	18	250	8,105	8,105	
	.9 Lead and Copper Rule	2,466	413	-	129	-	295	-	118	3,036	59	119	353	6,988	6,988	
	10 Env Auditing/Assessment	147	-	-	-	-	15	-	9	-	-	7,559	(273)	7,457	7,457	
	11 General Solid & Hazardous Waste	24,077	8,696	16,589	16,646	30,739	10,100	20,394	11,246	6,401	35,687	63,541	15,095	259,211	259,211	
	.12 Above Ground Storage Tanks	-	-	-	-	-	16,196	-	1,150	-	-	-	14,461	31,807	31,807	
	.13 Low Nox	-	3,083	-	-	-	-	-	(3,083)	-	-	81	877	958		958
	.14 Ash Pond Diversion Curtains	-	-	-	-	-	-	-	-	-	-	-	-	0		0
	15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0		0
	16 Sodium Injection	15,304	8,289	4,135	-	4,302	3,586	-	4,094	4,275	-	-	6,501	50,486		50,486
	17 Gulf Coast Ozone Study	442	2,123	1,833	2,222	2,340	645	28	2,268	-	-	2,217	6,231	20,349		20,349
	18 SO2 Allowances	(7,258)	(7,057)	(1,856)	875	1,567	(19,328)	(19,160)	(19,185)	(19,270)	(19,565)	(19,942)	(12,145)	(142,324)		(142,324)
2	Total of O & M Activities	111,694	715,949	73,927	125,321	256,592	165,482	129,083	109,378	67,153	311,600	150,808	413,871	2,630,858	1,382,965	1,247,893
3	Recoverable Costs Allocated to Energy	30,847	645,558	17,246	34,888	47,932	33,385	(9,932)	51,743	28,160	204,279	26,220	137,567	1,247,893		
4	Recoverable Costs Allocated to Demand	80,847	70,391	56,681	90,433	208,660	132,097	139,015	57,635	38,993	107,321	124,588	276,304	1,382,965		
5	Retail Energy Jurisdictional Factor	0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660			
6	Retail Demand Jurisdictional Factor	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747			
7	Jurisdictional Energy Recoverable Costs (A)	29,839	624,130	16,698	33,802	46,449	32,350	(9,624)	50,062	27,243	197,864	25,323	132,386	1,206,522		
8	Jurisdictional Demand Recoverable Costs (B)	78,023	67,933	54,701	87,275	201,372	127,483	134,160	55,622	37,631	103,573	120,237	266,654	1,334,664		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	107,862	692,063	71,399	121,077	247,821	159,833	124,536	105,684	64,874	301,437	145,560	399,040	2,541,186		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

Schedule 6A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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	5,905	6,047	(142)	(2.3)	%
.2	Crist 5, 6 & 7 Precipitator Projects	2,908,838	2,908,838	0	0.0	%
.3	Crist 7 Flue Gas Conditioning	254,767	254,767	0	0.0	%
.4	Low NOx Burners, Crist 6 & 7	1,956,115	1,956,115	0	0.0	%
.5	CEMS - Crist 1, 4-7, 6&7 Upgrade; Scholz 1; Smith 1 & 2; Daniel	720,364	718,703	1,661	0.2	%
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	115,425	115,427	(2)	(0.0)	%
.7	Raw Water Well Flowmeters - Plants Crist & Smith	34,566	34,566	0	0.0	%
.8	Crist Cooling Tower Cell	106,581	106,581	0	0.0	%
.9	Crist 1-5 Dechlorination	37,362	37,362	0	0.0	%
.10	Crist Diesel Fuel Oil Remediation	5,797	5,797	0	0.0	%
.11	Crist Bulk Tanker Unload Sec Contain Struc	12,430	12,430	0	0.0	%
.12	Crist IWW Sampling System	7,256	7,256	0	0.0	%
.13	Smith Sodium Injection System	14,234	14,234	0	0.0	%
.14	Smith Stormwater Collection System	333,873	333,873	0	0 0	%
.15	Smith Waste Water Treatment Facility	20,426	20,426	0	0.0	%
.16	Daniel Ash Management Project	1,994,128	1,994,129	(1)	(0.0)	%
.17	Smith Shield Water Project	6,723	6,725	(2)	(0.0)	%
.18	Underground Fuel Tank Replacement	75,169	75,169	0	0.0	%
.19	SO2 Allowances	(68,099)	(68,046)	(53)	(0.1)	%
2	Total Investment Projects - Recoverable Costs	8,541,860	8,540,399	1,461	0.0	%
3	Recoverable Costs Allocated to Energy	6,003,639	6,002,172	1,467	0.0	%
4	Recoverable Costs Allocated to Demand	2,538,221	2,538,227	(6)	(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-02-1735-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Schedule 7A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated 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	243	243	243	245	249	261	494	726	726	786	844	845	5,905	0	5,905
	2 *Crist 5, 6 & 7 Precipitator Projects*	239,665	238,845	238,027	238,311	240,020	246,044	246,879	245,988	245,100	244,209	243,318	242,432	2,908,838	0	2,908,838
	3 Crist 7 Flue Gas Conditioning	20,899	20,837	20,771	20,813	20,984	21,565	21,655	21,588	21,517	21,449	21,378	21,311	254,767	0	254,767
	4 Low NOx Burners, Crist 6 & 7	160,139	159,680	159,220	159,576	160,993	165,616	166,397	165,899	165,397	164,899	164,400	163,899	1,956,115	0	1,956,115
	.5 CEMS - Crist 1, 4-7, 6&7 Upgrade; Scholz 1, Smith 1	59,061	59,395	59,268	59,469	59,058	59,782	60,103	59,816	59,958	60,657	61,455	62,342	720,364	0	720,364
	.6 *Sub. Contam. Mobile Groundwater Treat Sys.*	8,488	8,481	8,494	9,114	9,783	10,133	10,203	10,184	10,167	10,145	10,126	10,107	115,425	106,547	8,878
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	2,811	2,804	2,798	2,807	2,837	2,930	2,948	2,941	2,933	2,926	2,919	2,912	34,566	31,907	2,659
	.8 Crist Cooling Tower Cell	8,750	8,724	8,698	8,712	8,782	9,020	9,056	9,027	8,996	8,969	8,937	8,910	106,581	98,383	8,198
	.9 Crist 1-5 Dechlorination	3,056	3,048	3,039	3,046	3,074	3,164	3,179	3,171	3,160	3,151	3,142	3,132	37,362	34,489	2,873
	10 *Crist Diesel Fuel Oil Remediation*	474	473	471	473	478	491	494	491	490	489	487	486	5,797	5,352	445
	11 Crist Bulk Tanker Unload Sec Contam Struc	1,017	1,014	1,011	1,014	1,023	1,053	1,058	1,054	1,052	1,048	1,045	1,041	12,430	11,474	956
	.12 Crist IWW Sampling System	594	591	591	591	598	614	618	615	614	612	610	608	7,256	6,699	557
	.13 Smith Sodium Injection System	1,156	1,153	1,151	1,155	1,168	1,207	1,214	1,211	1,209	1,206	1,203	1,201	14,234	0	14,234
	.14 *Smith Stormwater* Collection System	27,197	27,130	27,064	27,147	27,423	28,289	28,451	28,379	28,307	28,234	28,162	28,090	333,873	308,191	25,682
	15 Smith Waste Water Treatment Facility	1,665	1,662	1,657	1,662	1,678	1,731	1,740	1,735	1,731	1,726	1,722	1,717	20,426	18,856	1,570
	16 Daniel Ash Management Project	163,566	163,212	162,859	163,193	164,421	168,353	169,048	168,663	168,280	167,895	167,512	167,126	1,994,128	1,840,732	153,396
	.17 Smith Shield Water Project	546	544	544	545	552	570	574	573	571	569	569	566	6,723	6,205	518
	18 Underground Fuel Tank Replacement	6,437	6,394	6,353	6,320	6,301	6,320	6,289	6,244	6,196	6,151	6,105	6,059	75,169	69,386	5,783
	.19 SO2 Allowances	(5,413)	(4,992)	(4,596)	(4,627)	(4,730)	(5,865)	(6,765)	(6,584)	(6,402)	(6,220)	(6,033)	(5,882)	(68,099)	0	(68,099)
2	Total Investment Projects - Recoverable Costs	700,351	699,238	697,663	699,566	704,702	721,278	723,635	721,721	720,002	718,901	717,901	716,902	8,541,860	2,538,221	6,003,639
3	Recoverable Costs Allocated to Energy	493,027	492,397	491,282	492,219	495,209	506,506	507,953	506,573	505,388	504,826	504,361	503,898	6,003,639		
4	Recoverable Costs Allocated to Demand	207,324	206,841	206,381	207,347	209,493	214,772	215,682	215,148	214,614	214,075	213,540	213,004	2,538,221		
5	Retail Energy Jurisdictional Factor	0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660			
6	Retail Demand Jurisdictional Factor	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747			
7	Jurisdictional Energy Recoverable Costs (B)	476,914	476,053	475,658	476,892	479,885	490,798	492,177	490,119	488,926	488,972	487,099	484,921	5,808,414		
8	Jurisdictional Demand Recoverable Costs (C)	200,083	199,617	199,173	200,105	202,176	207,271	208,149	207,634	207,119	206,598	206,082	205,565	2,449,572		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	676,997	675,670	674,831	676,997	682,061	698,069	700,326	697,753	696,045	695,570	693,181	690,486	8,257,986		

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
(C) Line 4 x Line 6

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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	49,031	(23)	3	12,573	(81)	138	
	b Clearings to Plant		23,439	0	0	0	0	0	4,502	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)	239,115	262,554	262,554	262,554	262,554	262,554	262,554	267,056	267,056	267,056	267,056	267,056	267,056	
3	Less. Accumulated Depreciation (C)	(239,115)	(239,115)	(239,115)	(239,115)	(239,115)	(239,115)	(239,115)	(239,115)	(239,115)	(239,115)	(239,115)	(239,115)	(239,115)	
4	CWIP - Non Interest Bearing	27,941	4,502	4,502	4,502	4,502	4,502	4,502	49,031	49,008	49,011	61,584	61,503	61,641	
5	Net Investment (Lines 2 - 3 + 4)	27,941	27,941	27,941	27,941	27,941	27,941	27,941	76,972	76,949	76,952	89,525	89,444	89,582	
6	Average Net Investment		27,941	27,941	27,941	27,941	27,941	27,941	52,457	76,961	76,951	83,239	89,485	89,513	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		161	161	161	163	167	198	385	565	565	612	657	658	4,453
	b Debt Component (Line 6 x Debt Component x 1/12)		82	82	82	82	82	63	109	161	161	174	187	187	1,452
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	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)		243	243	243	245	249	261	494	726	726	786	844	845	5,905
	a Recoverable Costs Allocated to Energy		243	243	243	245	249	261	494	726	726	786	844	845	5,905
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		235	235	235	237	241	253	479	702	702	761	815	813	5,708
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)		235	235	235	237	241	253	479	702	702	761	815	813	5,708

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) .5823% (Apr) .5978% (May) .7073% (June) and 7347% (Jul-Dec). The approved ROE was 11 5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 1.0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1.0007 for July - Dec (Line loss factor changed as a result of Order No PSC-02-0787-FOF-EI in Doc. No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the *Final True-Up Amount*
January 2002 - December 2002

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)	(7,656,892)	(7,751,215)	(7,845,537)	(7,939,860)	(8,034,183)	(8,128,505)	(8,222,828)	(8,317,151)	(8,411,473)	(8,505,797)	(8,600,120)	(8,694,442)	(8,788,768)	
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)	16,783,933	16,689,610	16,595,288	16,500,965	16,406,642	16,312,320	16,217,997	16,123,674	16,029,352	15,935,028	15,840,705	15,746,383	15,652,057	
6	*Average Net Investment*		16,736,772	16,642,449	16,548,127	16,453,804	16,359,481	16,265,159	16,170,836	16,076,513	15,982,190	15,887,867	15,793,544	15,699,220	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		96,337	95,794	95,251	95,811	97,797	115,043	118,807	118,114	117,421	116,728	116,035	115,342	1,298,480
	b Debt Component (Line 6 x Debt Component x 1/12)		49,005	48,729	48,453	48,177	47,901	36,678	33,749	33,552	33,355	33,158	32,961	32,764	478,482
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		14,890	14,890	14,890	14,890	14,890	14,891	14,890	14,890	14,891	14,890	14,890	14,892	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)		239,665	238,845	238,027	238,311	240,020	246,044	246,879	245,988	245,100	244,209	243,318	242,432	2,908,838
	a Recoverable Costs Allocated to Energy		239,665	238,845	238,027	238,311	240,020	246,044	246,879	245,988	245,100	244,209	243,318	242,432	2,908,838
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		231,832	230,917	230,457	230,890	232,593	238,413	239,212	237,998	237,116	236,540	234,990	233,302	2,814,260
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)		231,832	230,917	230,457	230,890	232,593	238,413	239,212	237,998	237,116	236,540	234,990	233,302	2,814,260

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) These monthly equity components grossed up for taxes were applicable: 5756% (Jan-Mar) .5823% (Apr) .5978% (May) .7073% (June) and 7347% (Jul-Dec). The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc 010949-EI
(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 1.0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1 0007 for July - Dec. (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc. No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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)	(613,946)	(621,284)	(628,624)	(635,962)	(643,302)	(650,640)	(657,980)	(665,318)	(672,658)	(679,996)	(687,336)	(694,674)	(702,014)	
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)	1,565,299	1,557,961	1,550,621	1,543,283	1,535,943	1,528,605	1,521,265	1,513,927	1,506,587	1,499,249	1,491,909	1,484,571	1,477,231	
6	Average Net Investment		1,561,630	1,554,291	1,546,952	1,539,613	1,532,274	1,524,935	1,517,596	1,510,257	1,502,918	1,495,579	1,488,240	1,480,901	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		8,989	8,946	8,904	8,965	9,160	10,786	11,150	11,096	11,042	10,988	10,934	10,880	121,840
	b Debt Component (Line 6 x Debt Component x 1/12)		4,572	4,551	4,529	4,508	4,486	3,439	3,167	3,152	3,137	3,121	3,106	3,091	44,859
8	Investment Expenses														
	a Depreciation (E)		7,082	7,083	7,082	7,083	7,082	7,083	7,082	7,083	7,082	7,083	7,082	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)		20,899	20,837	20,771	20,813	20,984	21,565	21,655	21,588	21,517	21,449	21,378	21,311	254,767
	a Recoverable Costs Allocated to Energy		20,899	20,837	20,771	20,813	20,984	21,565	21,655	21,588	21,517	21,449	21,378	21,311	254,767
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		20,216	20,145	20,110	20,165	20,335	20,896	20,982	20,887	20,816	20,775	20,646	20,508	246,481
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)		20,216	20,145	20,110	20,165	20,335	20,896	20,982	20,887	20,816	20,775	20,646	20,508	246,481

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) 5823% (Apr) .5978% (May) 7073% (June) and .7347% (Jul-Dec) The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 1.0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No PSC-02-0787-FOF-EI in Doc No 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Cnst 6 & 7
P E.s 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	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)	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)	(3,928,081)	(3,981,044)	(4,034,007)	(4,086,970)	(4,139,933)	(4,192,897)	(4,245,859)	(4,298,822)	(4,351,786)	(4,404,748)	(4,457,711)	(4,510,675)	(4,563,638)	
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)	12,368,278	12,315,315	12,262,352	12,209,389	12,156,426	12,103,462	12,050,500	11,997,537	11,944,573	11,891,611	11,838,648	11,785,684	11,732,721	
6	Average Net Investment		12,341,797	12,288,834	12,235,871	12,182,908	12,129,944	12,076,981	12,024,019	11,971,055	11,918,092	11,865,130	11,812,166	11,759,203	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		71,039	70,735	70,430	70,941	72,513	85,420	88,340	87,951	87,562	87,173	86,784	86,395	965,283
	b Debt Component (Line 6 x Debt Component x 1/12)		36,137	35,982	35,827	35,672	35,516	27,234	25,094	24,984	24,873	24,763	24,652	24,541	355,275
8	Investment Expenses														
	a Depreciation (E)		52,963	52,963	52,963	52,963	52,964	52,962	52,963	52,964	52,962	52,963	52,964	52,963	635,557
	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)		160,139	159,680	159,220	159,576	160,993	165,616	166,397	165,899	165,397	164,899	164,400	163,899	1,956,115
	a Recoverable Costs Allocated to Energy		160,139	159,680	159,220	159,576	160,993	165,616	166,397	165,899	165,397	164,899	164,400	163,899	1,956,115
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		154,905	154,380	154,157	154,607	156,011	160,480	161,229	160,510	160,010	159,720	158,773	157,726	1,892,508
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)		154,905	154,380	154,157	154,607	156,011	160,480	161,229	160,510	160,010	159,720	158,773	157,726	1,892,508

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) .5823% (Apr) .5978% (May) 7073% (June) and .7347% (Jul-Dec). The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No PSC-02-0787-FOF-EI in Doc. No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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	0	0	0	0	0	0	0	114,699	59,477	133,695	(2,207)	
	b Clearings to Plant		367,234	0	0	0	0	0	68,987	0	0	0	0	477,832	
	c Retirements		0	0	0	0	821,725	147,657	0	193,401	0	0	0	260,243	
	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	3,600	(1,800)	1,800	0	
2	Plant-in-Service/Depreciation Base (B)	4,838,269	5,205,503	5,205,503	5,205,503	5,205,503	4,383,778	4,236,121	4,305,108	4,111,707	4,111,707	4,111,707	4,111,707	4,329,296	
3	Less: Accumulated Depreciation (C)	(590,695)	(605,055)	(619,876)	(634,698)	(649,520)	158,432	293,545	281,081	462,189	446,563	436,338	422,512	670,339	
4	CWIP - Non Interest Bearing	736,699	369,465	369,465	369,465	369,465	369,465	369,465	300,478	300,478	415,177	474,654	608,349	128,310	
5	Net Investment (Lines 2 + 3 + 4)	4,984,273	4,969,913	4,955,092	4,940,270	4,925,448	4,911,675	4,899,131	4,886,667	4,874,374	4,973,447	5,022,699	5,142,568	5,127,945	
6	Average Net Investment		4,977,093	4,962,503	4,947,681	4,932,859	4,918,562	4,905,403	4,892,899	4,880,521	4,923,911	4,998,073	5,082,634	5,135,257	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		28,648	28,564	28,479	28,724	29,403	34,696	35,948	35,857	36,176	36,721	37,342	37,729	398,287
	b Debt Component (Line 6 x Debt Component x 1/12)		14,573	14,530	14,487	14,443	14,402	11,062	10,211	10,186	10,276	10,431	10,607	10,717	145,925
8	Investment Expenses														
	a Depreciation (E)		14,360	14,821	14,822	14,822	13,773	12,544	12,464	12,293	12,026	12,025	12,026	12,416	158,392
	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		1,480	1,480	1,480	1,480	1,480	1,480	1,480	1,480	1,480	1,480	1,480	1,480	17,760
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		59,061	59,395	59,268	59,469	59,058	59,782	60,103	59,816	59,958	60,657	61,455	62,342	720,364
	a Recoverable Costs Allocated to Energy		59,061	59,395	59,268	59,469	59,058	59,782	60,103	59,816	59,958	60,657	61,455	62,342	720,364
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9659639	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		57,131	57,423	57,383	57,617	57,231	57,928	58,236	57,873	58,005	58,752	59,352	59,994	696,925
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)		57,131	57,423	57,383	57,617	57,231	57,928	58,236	57,873	58,005	58,752	59,352	59,994	696,925

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $2,234,010; Scholz $869,366; Smith $1,169,030; and Daniel $565,863. Ending Balances Crist $2,590,992; Scholz $486,599; Smith $565,863; and Daniel $565,863
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) 5823% (Apr) 5978% (May) .7073% (June) and .7347% (Jul-Dec) The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc 010949-EI
(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 1.0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No PSC-02-0787-FOF-EI in Doc No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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	5,017	(5,017)	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	549,020	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)	380,374	380,374	380,374	380,374	929,394	929,394	929,394	929,394	929,394	929,394	929,394	929,394	929,394	
3	Less: Accumulated Depreciation (C)	(55,570)	(56,473)	(57,377)	(58,281)	(59,756)	(61,803)	(63,853)	(65,900)	(67,947)	(69,996)	(72,043)	(74,090)	(76,138)	
4	CWIP - Non Interest Bearing	549,020	549,020	549,020	554,037	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 -,3 + 4)	873,824	872,921	872,017	876,130	869,638	867,591	865,541	863,494	861,447	859,398	857,351	855,304	853,256	
6	Average Net Investment		873,373	872,470	874,073	872,884	868,615	866,567	864,518	862,471	860,423	858,375	856,328	854,281	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		5,027	5,022	5,031	5,083	5,193	6,129	6,352	6,337	6,322	6,306	6,291	6,276	69,369
	b Debt Component (Line 6 x Debt Component x 1/12)		2,557	2,555	2,559	2,556	2,543	1,954	1,804	1,800	1,796	1,791	1,787	1,783	25,485
8	Investment Expenses														
	a Depreciation (E)		768	769	768	1,340	1,912	1,914	1,912	1,912	1,913	1,912	1,912	1,912	18,944
	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)		8,488	8,481	8,494	9,114	9,783	10,133	10,203	10,184	10,167	10,145	10,126	10,107	115,422
	a Recoverable Costs Allocated to Energy		653	653	653	701	752	779	785	784	781	780	780	777	8,878
	b Recoverable Costs Allocated to Demand		7,835	7,828	7,841	8,413	9,031	9,354	9,418	9,400	9,386	9,365	9,346	9,330	106,547
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		632	631	632	679	729	755	761	759	756	756	753	748	8,591
13	Retail Demand-Related Recoverable Costs (I)		7,561	7,555	7,567	8,119	8,716	9,027	9,089	9,072	9,058	9,038	9,020	9,004	102,826
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,193	8,186	8,199	8,798	9,445	9,782	9,850	9,831	9,814	9,794	9,773	9,752	111,417

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning balance of depreciable property $369,004; 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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) 5823% (Apr) .5978% (May) .7073% (June) and .7347% (Jul-Dec). The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 1.0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No PSC-02-0787-FOF-EI in Doc. No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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)	(4,457)	(5,200)	(5,943)	(6,686)	(7,429)	(8,172)	(8,915)	(9,658)	(10,401)	(11,144)	(11,887)	(12,630)	(13,373)	
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)	238,486	237,743	237,000	236,257	235,514	234,771	234,028	233,285	232,542	231,799	231,056	230,313	229,570	
6	Average Net Investment		238,115	237,372	236,629	235,886	235,143	234,400	233,657	232,914	232,171	231,428	230,685	229,942	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		1,371	1,366	1,362	1,374	1,406	1,658	1,717	1,711	1,706	1,700	1,695	1,689	18,755
	b Debt Component (Line 6 x Debt Component x 1/12)		697	695	693	691	688	529	488	486	485	483	481	480	6,896
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)		2,811	2,804	2,798	2,807	2,837	2,930	2,948	2,941	2,933	2,926	2,919	2,912	34,567
	a Recoverable Costs Allocated to Energy		217	215	215	216	218	225	227	227	225	225	225	224	2,659
	b Recoverable Costs Allocated to Demand		2,594	2,589	2,583	2,591	2,619	2,705	2,721	2,714	2,708	2,701	2,694	2,688	31,907
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		210	208	208	209	211	218	220	220	218	218	217	216	2,573
13	Retail Demand-Related Recoverable Costs (I)		2,503	2,499	2,493	2,501	2,528	2,611	2,626	2,619	2,613	2,607	2,600	2,594	30,794
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,713	2,707	2,701	2,710	2,739	2,829	2,846	2,839	2,831	2,825	2,817	2,810	33,367

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) .5823% (Apr) .5978% (May) .7073% (June) and .7347% (Jul-Dec). The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 1.0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Cust 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)	(260,150)	(263,300)	(266,451)	(269,603)	(272,754)	(275,905)	(279,056)	(282,206)	(285,357)	(288,507)	(291,659)	(294,809)	(297,961)	
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)	646,509	643,359	640,208	637,056	633,905	630,754	627,603	624,453	621,302	618,152	615,000	611,850	608,698	
6	Average Net Investment		644,934	641,784	638,632	635,481	632,330	629,179	626,028	622,878	619,727	616,576	613,425	610,274	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		3,712	3,694	3,676	3,700	3,780	4,450	4,599	4,576	4,553	4,530	4,507	4,484	50,261
	b Debt Component (Line 6 x Debt Component x 1/12)		1,888	1,879	1,870	1,861	1,851	1,419	1,307	1,300	1,293	1,287	1,280	1,274	18,509
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	205	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)		8,750	8,724	8,698	8,712	8,782	9,020	9,056	9,027	8,996	8,969	8,937	8,910	106,581
	a Recoverable Costs Allocated to Energy		673	671	669	670	676	694	697	694	692	690	687	685	8,198
	b Recoverable Costs Allocated to Demand		8,077	8,053	8,029	8,042	8,106	8,326	8,359	8,333	8,304	8,279	8,250	8,225	98,383
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		651	649	648	649	655	672	675	671	669	668	663	659	7,929
13	Retail Demand-Related Recoverable Costs (I)		7,795	7,772	7,749	7,761	7,823	8,035	8,067	8,042	8,014	7,990	7,962	7,938	94,948
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,446	8,421	8,397	8,410	8,478	8,707	8,742	8,713	8,683	8,658	8,625	8,597	102,877

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) 5823% (Apr) .5978% (May) 7073% (June) and 7347% (Jul-Dec). The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 1.0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc. No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 1-5 Dechlorination
P.E. 1248
(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)	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)	(67,083)	(68,075)	(69,067)	(70,059)	(71,051)	(72,043)	(73,036)	(74,028)	(75,021)	(76,013)	(77,005)	(77,998)	(78,990)	
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)	238,240	237,248	236,256	235,264	234,272	233,280	232,287	231,295	230,302	229,310	228,318	227,325	226,333	
6	Average Net Investment		237,744	236,752	235,760	234,768	233,776	232,784	231,791	230,799	229,806	228,814	227,822	226,829	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		1,368	1,363	1,357	1,367	1,398	1,646	1,703	1,696	1,688	1,681	1,674	1,667	18,608
	b Debt Component (Line 6 x Debt Component x 1/12)		696	693	690	687	684	525	484	482	480	478	475	473	6,847
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)		3,056	3,048	3,039	3,046	3,074	3,164	3,179	3,171	3,160	3,151	3,142	3,132	37,362
	a Recoverable Costs Allocated to Energy		235	234	234	234	236	243	245	244	243	242	242	241	2,873
	b Recoverable Costs Allocated to Demand		2,821	2,814	2,805	2,812	2,838	2,921	2,934	2,927	2,917	2,909	2,900	2,891	34,489
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		227	226	227	227	229	235	237	236	235	234	234	232	2,779
13	Retail Demand-Related Recoverable Costs (I)		2,722	2,716	2,707	2,714	2,739	2,819	2,832	2,825	2,815	2,807	2,799	2,790	33,285
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,949	2,942	2,934	2,941	2,968	3,054	3,069	3,061	3,050	3,041	3,033	3,022	36,064

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) .5823% (Apr) .5978% (May) .7073% (June) and 7347% (Jul-Dec). The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 0014 line loss multiplier for Jan. - May, 1 0008 for June, and 1 0007 for July - Dec. (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc. No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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)	(11,194)	(11,350)	(11,506)	(11,662)	(11,818)	(11,974)	(12,130)	(12,286)	(12,442)	(12,598)	(12,754)	(12,910)	(13,066)	
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)	36,761	36,605	36,449	36,293	36,137	35,981	35,825	35,669	35,513	35,357	35,201	35,045	34,889	
6	Average Net Investment		36,683	36,527	36,371	36,215	36,059	35,903	35,747	35,591	35,435	35,279	35,123	34,967	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		211	210	209	211	216	254	263	261	260	259	258	257	2,869
	b Debt Component (Line 6 x Debt Component x 1/12)		107	107	106	106	106	81	75	74	74	74	73	73	1,056
8	Investment Expenses														
	a Depreciation (E)		156	156	156	156	156	156	156	156	156	156	156	156	1,872
	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)		474	473	471	473	478	491	494	491	490	489	487	486	5,797
	a Recoverable Costs Allocated to Energy		36	36	36	36	37	38	38	38	38	38	37	37	445
	b Recoverable Costs Allocated to Demand		438	437	435	437	441	453	456	453	452	451	450	449	5,352
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9630989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		35	35	35	35	36	37	37	37	37	37	36	36	433
13	Retail Demand-Related Recoverable Costs (I)		423	422	420	422	426	437	440	437	436	435	434	433	5,165
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		458	457	455	457	462	474	477	474	473	472	470	469	5,598

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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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) .5823% (Apr) .5978% (May) .7073% (June) and .7347% (Jul-Dec). The approved ROE was 11 5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 1.0014 line loss multiplier for Jan - May, 1.0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc. No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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)	(22,233)	(22,563)	(22,893)	(23,223)	(23,553)	(23,883)	(24,213)	(24,543)	(24,873)	(25,203)	(25,533)	(25,863)	(26,193)	
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)	79,262	78,932	78,602	78,272	77,942	77,612	77,282	76,952	76,622	76,292	75,962	75,632	75,302	
6	Average Net Investment		79,097	78,767	78,437	78,107	77,777	77,447	77,117	76,787	76,457	76,127	75,797	75,467	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		455	453	451	455	465	548	567	564	562	559	557	554	6,190
	b Debt Component (Line 6 x Debt Component x 1/12)		232	231	230	229	228	175	161	160	160	159	158	157	2,280
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)		1,017	1,014	1,011	1,014	1,023	1,053	1,058	1,054	1,052	1,048	1,045	1,041	12,430
	a Recoverable Costs Allocated to Energy		78	78	78	78	79	81	81	81	81	81	80	80	956
	b Recoverable Costs Allocated to Demand		939	936	933	936	944	972	977	973	971	967	965	961	11,474
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		75	75	76	76	77	78	78	78	78	78	77	77	923
13	Retail Demand-Related Recoverable Costs (I)		906	903	900	903	911	938	943	939	937	933	931	927	11,071
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		981	978	976	979	988	1,016	1,021	1,017	1,015	1,011	1,008	1,004	11,994

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) 5823% (Apr) .5978% (May) .7073% (June) and 7347% (Jul-Dec). The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 1.0014 line loss multiplier for Jan - May, 1.0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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)	(13,362)	(13,556)	(13,749)	(13,943)	(14,136)	(14,330)	(14,523)	(14,717)	(14,910)	(15,104)	(15,297)	(15,491)	(15,684)	
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)	46,181	45,987	45,794	45,600	45,407	45,213	45,020	44,826	44,633	44,439	44,246	44,052	43,859	
6	Average Net Investment		46,084	45,891	45,697	45,504	45,310	45,117	44,923	44,730	44,536	44,343	44,149	43,956	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		265	264	263	265	271	319	330	329	327	326	324	323	3,606
	b Debt Component (Line 6 x Debt Component x 1/12)		135	134	134	133	133	102	94	93	93	93	92	92	1,328
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)		594	591	591	591	598	614	618	615	614	612	610	608	7,256
	a Recoverable Costs Allocated to Energy		46	45	45	45	46	47	48	47	47	47	47	47	557
	b Recoverable Costs Allocated to Demand		548	546	546	546	552	567	570	568	567	565	563	561	6,699
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		44	44	44	44	45	46	47	45	45	46	45	45	540
13	Retail Demand-Related Recoverable Costs (I)		529	527	527	527	533	547	550	548	547	545	543	541	6,464
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		573	571	571	571	578	593	597	593	592	591	588	586	7,004

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) .5823% (Apr) .5978% (May) 7073% (June) and .7347% (Jul-Dec). The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 1.0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1.0007 for July - Dec (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc. No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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)	(6,958)	(7,251)	(7,544)	(7,837)	(8,130)	(8,423)	(8,716)	(9,009)	(9,302)	(9,595)	(9,888)	(10,181)	(10,474)	
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)	99,539	99,246	98,953	98,660	98,367	98,074	97,781	97,488	97,195	96,902	96,609	96,316	96,023	
6	Average Net Investment		99,393	99,100	98,807	98,514	98,221	97,928	97,635	97,342	97,049	96,756	96,463	96,170	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		572	570	569	574	587	693	717	715	713	711	709	707	7,837
	b Debt Component (Line 6 x Debt Component x 1/12)		291	290	289	288	288	221	204	203	203	202	201	201	2,881
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)		1,156	1,153	1,151	1,155	1,168	1,207	1,214	1,211	1,209	1,206	1,203	1,201	14,234
	a Recoverable Costs Allocated to Energy		1,156	1,153	1,151	1,155	1,168	1,207	1,214	1,211	1,209	1,206	1,203	1,201	14,234
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		1,118	1,115	1,114	1,119	1,132	1,170	1,176	1,172	1,170	1,168	1,162	1,156	13,772
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)		1,118	1,115	1,114	1,119	1,132	1,170	1,176	1,172	1,170	1,168	1,162	1,156	13,772

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) 5823% (Apr) .5978% (May) .7073% (June) and .7347% (Jul-Dec). The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc 010949-EI
(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 1.0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc No. 010949-EI)
(I) Line 9b x Line 11

02

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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)	(528,138)	(535,790)	(543,442)	(551,094)	(558,746)	(566,398)	(574,050)	(581,702)	(589,354)	(597,006)	(604,658)	(612,310)	(619,962)	
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)	2,254,462	2,246,810	2,239,158	2,231,506	2,223,854	2,216,202	2,208,550	2,200,898	2,193,246	2,185,594	2,177,942	2,170,290	2,162,638	
6	Average Net Investment		2,250,636	2,242,984	2,235,332	2,227,680	2,220,028	2,212,376	2,204,724	2,197,072	2,189,420	2,181,768	2,174,116	2,166,464	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		12,955	12,911	12,867	12,972	13,271	15,648	16,198	16,142	16,086	16,029	15,973	15,917	176,969
	b Debt Component (Line 6 x Debt Component x 1/12)		6,590	6,567	6,545	6,523	6,500	4,989	4,601	4,585	4,569	4,553	4,537	4,521	65,080
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)		27,197	27,130	27,064	27,147	27,423	28,289	28,451	28,379	28,307	28,234	28,162	28,090	333,873
	a Recoverable Costs Allocated to Energy		2,092	2,087	2,082	2,088	2,109	2,176	2,189	2,183	2,177	2,172	2,166	2,161	25,682
	b Recoverable Costs Allocated to Demand		25,105	25,043	24,982	25,059	25,314	26,113	26,262	26,196	26,130	26,062	25,996	25,929	308,191
10	Energy Jurisdictional Factor		0 9659659	0.9654552	0.9668446	0.9675073	0.9677012	0 9681736	0 9682646	0.9668420	0.9667508	0.9679181	0 9650989	0.9616660	
11	Demand Jurisdictional Factor		0 9650747	0.9650747	0 9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0 9650747	0.9650747	0 9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		2,024	2,018	2,016	2,023	2,044	2,109	2,121	2,112	2,106	2,104	2,092	2,080	24,849
13	Retail Demand-Related Recoverable Costs (I)		24,228	24,168	24,109	24,184	24,430	25,201	25,345	25,281	25,217	25,152	25,088	25,023	297,426
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		26,252	26,186	26,125	26,207	26,474	27,310	27,466	27,393	27,323	27,256	27,180	27,103	322,275

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) .5823% (Apr) .5978% (May) .7073% (June) and .7347% (Jul-Dec). The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 1.0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1 0007 for July - Dec. (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc No 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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)	(38,678)	(39,160)	(39,642)	(40,124)	(40,606)	(41,088)	(41,570)	(42,052)	(42,534)	(43,016)	(43,498)	(43,980)	(44,462)	
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)	136,522	136,040	135,558	135,076	134,594	134,112	133,630	133,148	132,666	132,184	131,702	131,220	130,738	
6	Average Net Investment		136,281	135,799	135,317	134,835	134,353	133,871	133,389	132,907	132,425	131,943	131,461	130,979	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		784	782	779	785	803	947	980	976	973	969	966	962	10,706
	b Debt Component (Line 6 x Debt Component x 1/12)		399	398	396	395	393	302	278	277	276	275	274	273	3,936
8	Investment Expenses														
	a Depreciation (E)		482	482	482	482	482	482	482	482	482	482	482	482	5,784
	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)		1,665	1,662	1,657	1,662	1,678	1,731	1,740	1,735	1,731	1,726	1,722	1,717	20,426
	a Recoverable Costs Allocated to Energy		128	128	127	128	129	133	134	133	133	133	132	132	1,570
	b Recoverable Costs Allocated to Demand		1,537	1,534	1,530	1,534	1,549	1,598	1,606	1,602	1,598	1,593	1,590	1,585	18,856
10	Energy Jurisdictional Factor		0 9659659	0 9654552	0.9668446	0 9675073	0.9677012	0.9681736	0 9682646	0.9668420	0 9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0 9650747	0 9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0 9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		124	124	123	124	125	129	130	129	129	129	127	127	1,520
13	Retail Demand-Related Recoverable Costs (I)		1,483	1,480	1,477	1,480	1,495	1,542	1,550	1,546	1,542	1,537	1,534	1,530	18,196
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,607	1,604	1,600	1,604	1,620	1,671	1,680	1,675	1,671	1,666	1,661	1,657	19,716

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) .5823% (Apr) 5978% (May) .7073% (June) and .7347% (Jul-Dec) The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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)	(2,840,451)	(2,881,169)	(2,921,887)	(2,962,605)	(3,003,323)	(3,044,041)	(3,084,759)	(3,125,477)	(3,166,195)	(3,206,913)	(3,247,630)	(3,288,348)	(3,329,065)	
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)	10,402,018	10,361,300	10,320,582	10,279,864	10,239,146	10,198,428	10,157,710	10,116,992	10,076,274	10,035,556	9,994,839	9,954,121	9,913,404	
6	Average Net Investment		10,381,659	10,340,941	10,300,223	10,259,505	10,218,787	10,178,069	10,137,351	10,096,633	10,055,915	10,015,198	9,974,480	9,933,763	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		59,757	59,522	59,288	59,741	61,088	71,989	74,479	74,180	73,881	73,582	73,283	72,983	813,773
	b Debt Component (Line 6 x Debt Component x 1/12)		30,397	30,278	30,159	30,040	29,921	22,952	21,157	21,072	20,987	20,902	20,817	20,732	299,414
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		32,694	32,694	32,694	32,694	32,694	32,694	32,694	32,693	32,694	32,694	32,694	32,694	392,327
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		163,566	163,212	162,859	163,193	164,421	168,353	169,048	168,663	168,280	167,895	167,512	167,126	1,994,128
	a Recoverable Costs Allocated to Energy		12,582	12,555	12,528	12,553	12,648	12,950	13,004	12,974	12,945	12,915	12,886	12,856	153,396
	b Recoverable Costs Allocated to Demand		150,984	150,657	150,331	150,640	151,773	155,403	156,044	155,689	155,335	154,980	154,626	154,270	1,840,732
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		12,171	12,138	12,130	12,162	12,257	12,548	12,600	12,553	12,523	12,509	12,445	12,372	148,408
13	Retail Demand-Related Recoverable Costs (I)		145,711	145,395	145,081	145,379	146,472	149,976	150,594	150,252	149,910	149,567	149,226	148,882	1,776,445
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		157,882	157,533	157,211	157,541	158,729	162,524	163,194	162,805	162,433	162,076	161,671	161,254	1,924,853

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) 5823% (Apr) .5978% (May) 7073% (June) and 7347% (Jul-Dec). The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 1.0014 line loss multiplier for Jan - May, 1.0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc. No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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)	(195)	(327)	(459)	(591)	(723)	(855)	(987)	(1,119)	(1,251)	(1,383)	(1,514)	(1,646)	(1,777)	
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)	47,711	47,579	47,447	47,315	47,183	47,051	46,919	46,787	46,655	46,523	46,392	46,260	46,129	
6	Average Net Investment		47,645	47,513	47,381	47,249	47,117	46,985	46,853	46,721	46,589	46,458	46,326	46,195	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		274	273	273	275	282	332	344	343	342	341	340	339	3,758
	b Debt Component (Line 6 x Debt Component x 1/12)		140	139	139	138	138	106	98	98	97	97	97	96	1,383
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)		546	544	544	545	552	570	574	573	571	569	569	566	6,723
	a Recoverable Costs Allocated to Energy		42	42	42	42	42	44	44	44	44	44	44	44	518
	b Recoverable Costs Allocated to Demand		504	502	502	503	510	526	530	529	527	525	525	522	6,205
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		41	41	41	41	41	43	43	43	43	43	42	42	504
13	Retail Demand-Related Recoverable Costs (I)		486	484	484	485	492	508	511	511	509	507	507	504	5,988
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		527	525	525	526	533	551	554	554	552	550	549	546	6,492

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) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) 5823% (Apr) .5978% (May) .7073% (June) and .7347% (Jul-Dec). The approved ROE was 11 5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(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 1.0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc. No. 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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)	(280,780)	(285,701)	(290,621)	(295,542)	(300,463)	(305,383)	(310,304)	(315,224)	(320,145)	(325,065)	(329,986)	(334,907)	(339,828)	
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)	177,139	172,218	167,298	162,377	157,456	152,536	147,615	142,695	137,774	132,854	127,933	123,012	118,091	
6	Average Net Investment		174,679	169,758	164,838	159,917	154,996	150,076	145,155	140,235	135,314	130,394	125,473	120,552	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		1,005	977	949	931	927	1,061	1,066	1,030	994	958	922	886	11,706
	b Debt Component (Line 6 x Debt Component x 1/12)		511	497	483	468	454	338	303	293	282	272	262	252	4,415
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	4,921	4,921	59,048
	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)		6,437	6,394	6,353	6,320	6,301	6,320	6,289	6,244	6,196	6,151	6,105	6,059	75,169
	a Recoverable Costs Allocated to Energy		495	492	489	486	485	486	484	480	477	473	470	466	5,783
	b Recoverable Costs Allocated to Demand		5,942	5,902	5,864	5,834	5,816	5,834	5,805	5,764	5,719	5,678	5,635	5,593	69,386
10	Energy Jurisdictional Factor		0 9659639	0.9654552	0 9668446	0 9675073	0.9677012	0.9681736	0.9682646	0 9668420	0.9667508	0 9679181	0.9650989	0 9616660	
11	Demand Jurisdictional Factor		0 9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0 9650747	0.9650747	0 9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (H)		479	476	473	471	470	471	469	464	461	458	454	448	5,594
13	Retail Demand-Related Recoverable Costs (I)		5,734	5,696	5,659	5,630	5,613	5,630	5,602	5,563	5,519	5,480	5,438	5,398	66,962
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		6,213	6,172	6,132	6,101	6,083	6,101	6,071	6,027	5,980	5,938	5,892	5,846	72,556

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) These monthly equity components grossed up for taxes were applicable: 5756% (Jan-Mar) .5823% (Apr) .5978% (May) 7073% (June) and .7347% (Jul-Dec) The approved ROE was 11 5% (Jan-Mar) and 12% (Apr-Dec) See Doc 010949-EI
(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 1.0014 line loss multiplier for Jan. - May, 1 0008 for June, and 1.0007 for July - Dec. (Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc. No 010949-EI)
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2002 - December 2002

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	(82,424)	0	0	0	215,194	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158 1 Allowance Inventory	52,331	51,063	49,595	48,620	47,745	46,178	44,162	41,978	39,819	37,745	35,966	34,564	32,680	
	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	(679,266)	(670,740)	(579,791)	(576,960)	(576,960)	(576,960)	(770,810)	(749,466)	(728,122)	(706,778)	(685,434)	(664,090)	(650,061)	
3	Total Working Capital Balance	(626,935)	(619,677)	(530,196)	(528,340)	(529,215)	(530,782)	(726,648)	(707,488)	(688,303)	(669,033)	(649,468)	(629,526)	(617,381)	
4	Average Net Working Capital Balance		(623,306)	(574,937)	(529,268)	(528,778)	(529,999)	(628,715)	(717,068)	(697,896)	(678,668)	(659,251)	(639,497)	(623,454)	
5	Return on Average Net Working Capital Balance														
	a Equity Component Grossed Up For Taxes (A)		(3,588)	(3,309)	(3,046)	(3,079)	(3,168)	(4,447)	(5,268)	(5,127)	(4,986)	(4,844)	(4,698)	(4,581)	(50,141)
	b Debt Component (Line 4 x 3.5137% x 1/12)		(1,825)	(1,683)	(1,550)	(1,548)	(1,552)	(1,418)	(1,497)	(1,457)	(1,416)	(1,376)	(1,335)	(1,301)	(17,958)
6	Total Return Component (D)		(5,413)	(4,992)	(4,596)	(4,627)	(4,720)	(5,865)	(6,765)	(6,584)	(6,402)	(6,220)	(6,033)	(5,882)	(68,099)
7	Expenses														
	a Gains		(8,526)	(8,525)	(2,831)	0	0	(21,344)	(21,344)	(21,344)	(21,344)	(21,344)	(21,344)	(14,029)	(161,975)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		1,268	1,468	975	875	1,567	2,016	2,184	2,159	2,074	1,779	1,402	1,884	19,651
8	Net Expenses (E)		(7,258)	(7,057)	(1,856)	875	1,567	(19,328)	(19,160)	(19,185)	(19,270)	(19,565)	(19,942)	(12,145)	(142,324)
9	Total System Recoverable Expenses (Lines 6 + 7)		(12,671)	(12,049)	(6,452)	(3,752)	(3,153)	(25,193)	(25,925)	(25,769)	(25,672)	(25,785)	(25,975)	(18,027)	(210,423)
	a Recoverable Costs Allocated to Energy		(12,671)	(12,049)	(6,452)	(3,752)	(3,153)	(25,193)	(25,925)	(25,769)	(25,672)	(25,785)	(25,975)	(18,027)	(210,423)
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9659659	0.9654552	0.9668446	0.9675073	0.9677012	0.9681736	0.9682646	0.9668420	0.9667508	0.9679181	0.9650989	0.9616660	
11	Demand Jurisdictional Factor		0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	
12	Retail Energy-Related Recoverable Costs (B)		(12,257)	(11,649)	(6,247)	(3,635)	(3,055)	(24,412)	(25,120)	(24,932)	(24,836)	(24,975)	(25,086)	(17,348)	(203,552)
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)		(12,257)	(11,649)	(6,247)	(3,635)	(3,055)	(24,412)	(25,120)	(24,932)	(24,836)	(24,975)	(25,086)	(17,348)	(203,552)

Notes:
(A) These monthly equity components grossed up for taxes were applicable: .5756% (Jan-Mar) .5823% (Apr) .5978% (May) .7073% (June) and .7347% (Jul-Dec). The approved ROE was 11.5% (Jan-Mar) and 12% (Apr-Dec) See Doc. 010949-EI
(B) Line 9a x Line 10 x 1.0014 line loss multiplier for Jan. - May, 1.0008 for June, and 1.0007 for July - Dec. *(Line loss factor changed as a result of Order No. PSC-02-0787-FOF-EI in Doc No 010949-EI)*
(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

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Schedule 1E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2003 - December 2003

Line		Period Amount ($)
1	Over/(Under) Recovery for the current period (Schedule 2E, Line 5)	203,908
2	Interest Provision (Schedule 2E, Line 6)	5,255
3	Sum of Current Period Adjustments (Schedule 2E, Line 10)	0
4	Current Period True-Up Amount to be refunded/(recovered) in the projection period January 2004 - December 2004 (Lines 1 + 2 + 3)	209,163

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030007-EI EXHIBIT NO. Comp
COMPANY/ GULF
WITNESS: S.D.R.
DATE: 11-12-03

Comp. ex 3

SDR-2

Schedule 2E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated 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	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	930,949	713,397	742,213	780,800	979,621	1,028,422	1,051,957	1,086,325	916,774	751,451	697,179	829,062	10,508,150
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	1,081,192	1,104,727	1,139,095	969,544	804,221	749,949	881,839	11,141,397
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5E, Line 9)	735,991	141,781	136,421	131,288	209,343	162,004	185,685	314,599	186,855	186,757	198,232	211,571	2,800,527
	b Capital Investment Projects (Schedule 7E, Line 9)	687,993	686,705	684,788	683,299	680,987	678,132	674,004	673,266	671,507	670,405	669,604	676,272	8,136,962
	c Total Jurisdictional ECRC Costs	1,423,984	828,486	821,209	814,587	890,330	840,136	859,689	987,865	858,362	857,162	867,836	887,843	10,937,489
5	Over/(Under) Recovery (Line 3 - Line 4c)	(440,265)	(62,319)	(26,226)	18,983	142,061	241,056	245,038	151,230	111,182	(52,941)	(117,887)	(6,004)	203,908
6	Interest Provision (Schedule 3E, Line 10)	658	329	219	158	188	301	477	611	684	663	536	431	5,255
7	Beginning Balance True-Up & Interest Provision	633,247	140,870	26,110	(52,667)	(86,296)	3,183	191,770	384,515	483,586	542,682	437,634	267,513	633,247
	a Deferred True-Up from January 2002 - December 2002 (Schedule 1A, Line 3)	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)	370,470	255,710	176,933	143,304	232,783	421,370	614,115	713,186	772,282	667,234	497,113	438,763	438,763
10	Adjustments to Period Total True-Up Including Interest													0
11	Current Period Total Net True-Up (Lines 9 + 10)	370,470	255,710	176,933	143,304	232,783	421,370	614,115	713,186	772,282	667,234	497,113	438,763	438,763

Schedule 3E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2003 - December 2003

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)	862,847	370,470	255,710	176,933	143,304	232,783	421,370	614,115	713,186	772,282	667,234	497,113	
2	Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8)	369,812	255,381	176,714	143,146	232,595	421,069	613,638	712,575	771,598	666,571	496,577	438,332	
3	Total of Beginning & Ending True-up (Lines 1 + 2)	1,232,659	625,851	432,424	320,079	375,899	653,852	1,035,008	1,326,690	1,484,784	1,438,853	1,163,811	935,445	
4	Average True-Up Amount (Line 3 x 1/2)	616,330	312,926	216,212	160,040	187,950	326,926	517,504	663,345	742,392	719,427	581,906	467,723	
5	Interest Rate (First Day of Reporting Business Month)	0.012900	0.012700	0.012500	0.011800	0.011900	0.012100	0.010000	0.012100	0.010000	0.012100	0.010000	0.012100	
6	Interest Rate (First Day of Subsequent Business Month)	0.012700	0.012500	0.011800	0.011900	0.012100	0.010000	0.012100	0.010000	0.012100	0.010000	0.012100	0.010000	
7	Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.025600	0.025200	0.024300	0.023700	0.024000	0.022100	0.022100	0.022100	0.022100	0.022100	0.022100	0.022100	
8	Average Interest Rate (Line 7 x 1/2)	0.012800	0.012600	0.012150	0.011850	0.012000	0.011050	0.011050	0.011050	0.011050	0.011050	0.011050	0.011050	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.001067	0.001050	0.001013	0.000988	0.001000	0.000921	0.000921	0.000921	0.000921	0.000921	0.000921	0.000921	
10	Interest Provision for the Month (Line 4 x Line 9)	658	329	219	158	188	301	477	611	684	663	536	431	5,255

Schedule 4E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2003 - December 2003

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	30,000	30,000	0	0.0	%
.2	Air Emission Fees	759,817	759,817	0	0.0	%
.3	Title V	76,810	76,810	0	0.0	%
.4	Asbestos Fees	4,500	4,500	0	0.0	%
.5	Emission Monitoring	577,779	577,779	0	0.0	%
.6	General Water Quality	379,118	379,118	0	0.0	%
.7	Groundwater Contamination Investigation	895,305	394,797	500,508	126.8	%
.8	State NPDES Administration	49,500	49,500	0	0.0	%
.9	Lead and Copper Rule	16,500	16,500	0	0.0	%
.10	Env Auditing/Assessment	11,050	1,000	10,050	1,005.0	%
.11	General Solid & Hazardous Waste	190,208	190,208	0	0.0	%
.12	Above Ground Storage Tanks	25,000	25,000	0	0.0	%
.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	6,000	49,000	(43,000)	(87.8)	%
.17	Gulf Coast Ozone Study	82,559	235,000	(152,441)	(64.9)	%
.18	SO2 Allowances	(203,769)	(50,426)	(153,343)	304.1	%
2	Total O & M Activities	2,900,377	2,738,603	161,774	5.9	%
3	Recoverable Costs Allocated to Energy	1,329,196	1,677,980	(348,784)	(20.8)	%
4	Recoverable Costs Allocated to Demand	1,571,181	1,060,623	510,558	48.1	%

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-02-1735-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Schedule 6E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated 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	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	-	3,163	26,693	(10,863)	1,152	-	1,642	1,643	1,642	1,643	1,642	1,643	30,000		30,000
	.2 Air Emission Fees	629,153	-	-	-	-	93	-	130,571	-	-	-	-	759,817		759,817
	.3 Title V	8,342	6,010	6,866	7,195	5,909	7,246	6,007	6,007	6,007	6,007	6,007	6,007	76,810		76,810
	.4 Asbestos Fees	500	500	700	-	-	-	-	1,000	-	-	900	900	4,500	4,500	
	.5 Emission Monitoring	32,721	78,998	24,341	17,753	71,267	84,863	44,639	44,639	44,639	44,639	44,640	44,640	577,779		577,779
	.6 General Water Quality	20,482	8,906	12,697	9,918	25,911	10,656	48,425	48,425	48,425	48,425	48,425	48,423	379,118	379,118	
	.7 Groundwater Contamination Investigation	27,746	28,989	33,909	80,016	101,274	68,827	92,424	92,424	92,424	92,424	92,424	92,424	895,305	895,305	
	.8 State NPDES Administration	34,500	2,950	(2,950)	-	-	-	-	-	-	-	7,500	7,500	49,500	49,500	
	.9 Lead and Copper Rule	59	-	-	118	59	885	2,563	2,563	2,563	2,563	2,563	2,564	16,500	16,500	
	.10 Env Auditing/Assessment	833	-	454	439	1,377	1,947	1,000	1,000	1,000	1,000	1,000	1,000	11,050	11,050	
	.11 General Solid & Hazardous Waste	12,424	8,314	23,605	23,027	12,090	12,042	16,451	16,451	16,451	16,451	16,451	16,451	190,208	190,208	
	.12 Above Ground Storage Tanks	-	449	616	683	1,125	597	-	1,530	1,250	1,250	5,000	12,500	25,000	25,000	
	.13 Low Nox	-	-	-	-	-	-	-	-	-	-	-	-	0		0
	.14 Ash Pond Diversion Curtains	-	-	-	-	-	-	-	-	-	-	-	-	0		0
	.15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0		0
	.16 Sodium Injection	-	-	-	-	-	-	-	-	-	-	-	6,000	6,000		6,000
	.17 Gulf Coast Ozone Study	571	13,051	19,615	12,099	750	6,473	5,000	5,000	5,000	5,000	5,000	5,000	82,559		82,559
	.18 SO2 Allowances	(4,252)	(4,629)	(4,685)	(4,454)	(4,341)	(26,085)	(25,782)	(25,770)	(25,841)	(25,915)	(26,151)	(25,864)	(203,769)		(203,769)
2	Total of O & M Activities	763,079	166,701	141,061	135,931	216,573	167,544	192,369	325,483	193,560	193,487	205,401	219,188	2,908,377	1,571,181	1,329,196
3	Recoverable Costs Allocated to Energy	666,535	96,593	72,030	21,730	74,737	72,590	31,506	162,090	31,447	31,374	31,138	37,426	1,329,196		
4	Recoverable Costs Allocated to Demand	96,544	50,108	69,031	114,201	141,836	94,954	160,863	163,393	162,113	162,113	174,263	181,762	1,571,181		
5	Retail Energy Jurisdictional Factor	0.9637519	0.9665363	0.9684383	0.9695202	0.9689702	0.9687608	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763			
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	93,426	69,805	21,082	72,469	70,372	30,449	156,922	30,413	30,315	30,065	36,167	1,284,309		
8	Jurisdictional Demand Recoverable Costs (B)	93,167	48,355	66,616	110,296	136,874	91,632	155,236	157,677	156,442	156,442	168,167	175,404	1,516,218		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	735,991	141,781	136,421	131,288	209,343	162,004	185,685	314,599	186,855	186,757	198,232	211,571	2,800,527		

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 2003 - December 2003

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	13,907	13,211	696	5.3	%
.2	Crist 5, 6 & 7 Precipitator Projects	2,839,745	2,839,747	(2)	(0.0)	%
.3	Crist 7 Flue Gas Conditioning	250,318	250,322	(4)	(0.0)	%
.4	Low NOx Burners, Crist 6 & 7	1,942,098	1,952,348	(10,250)	(0.5)	%
.5	CEMS - Crist 1-7, 6&7 Upgrade; Scholz 1; Smith 1 & 2; Daniel	736,664	796,546	(59,882)	(7.5)	%
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	119,782	119,768	14	0.0	%
.7	Raw Water Well Flowmeters - Plants Crist & Smith	34,397	34,400	(3)	(0.0)	%
.8	Crist Cooling Tower Cell	104,580	104,585	(5)	(0.0)	%
.9	Crist 1-5 Dechlorination	36,856	36,853	3	0.0	%
.10	Crist Diesel Fuel Oil Remediation	5,715	5,715	0	0.0	%
.11	Crist Bulk Tanker Unload Sec Contain Struc	12,260	12,260	0	0.0	%
.12	Crist IWW Sampling System	7,157	7,162	(5)	(0.1)	%
.13	Smith Sodium Injection System	14,186	14,186	0	0.0	%
.14	Smith Stormwater Collection System	331,457	331,457	0	0.0	%
.15	Smith Waste Water Treatment Facility	20,252	20,254	(2)	(0.0)	%
.16	Daniel Ash Management Project	1,946,762	1,957,135	(10,373)	(0.5)	%
.17	Smith Shield Water Project	6,715	6,718	(3)	(0.0)	%
.18	Underground Fuel Tank Replacement	69,073	69,072	1	0.0	%
.19	SO2 Allowances	(75,168)	(66,108)	(9,060)	(13.1)	%
2	Total Investment Projects - Recoverable Costs	8,416,756	8,505,631	(88,875)	(1.0)	%
3	Recoverable Costs Allocated to Energy	5,929,056	6,008,357	(79,301)	(1.3)	%
4	Recoverable Costs Allocated to Demand	2,487,700	2,497,274	(9,574)	(0.4)	%

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-02-1735-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 2003 - December 2003

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	1,177	1,173	1,170	1,167	1,164	1,161	1,157	1,155	1,151	1,148	1,146	1,142	13,907	0	13,907
.2	Crist 5, 6 & 7 Precipitator Projects	241,539	240,649	239,760	238,870	237,980	237,090	236,200	235,309	234,422	233,531	232,642	231,753	2,839,745	0	2,839,745
.3	Crist 7 Flue Gas Conditioning	21,239	21,172	21,101	21,034	20,963	20,896	20,824	20,757	20,686	20,618	20,548	20,480	250,318	0	250,318
.4	Low NOx Burners, Crist 6 & 7	163,400	162,900	162,401	161,900	161,402	161,090	160,780	160,471	160,346	160,224	160,102	167,082	1,942,098	0	1,942,098
.5	CEMS - Crist 1-7, 6&7 Upgrade; Scholz 1; Smith 1 &	62,717	61,940	60,973	60,884	60,780	60,671	60,565	60,563	60,678	61,391	62,350	63,152	736,664	0	736,664
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	10,087	10,070	10,049	10,030	10,010	9,993	9,971	9,953	9,936	9,914	9,893	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	2,869	2,864	2,856	2,849	2,842	2,835	2,828	34,397	31,750	2,647
.8	Crist Cooling Tower Cell	8,879	8,848	8,820	8,789	8,760	8,729	8,701	8,670	8,639	8,612	8,581	8,552	104,580	96,536	8,044
.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	468	5,715	5,276	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	1,008	1,004	12,260	11,317	943
.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	1,184	1,180	1,178	1,175	1,173	1,170	1,167	14,186	0	14,186
.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	1,675	1,672	1,666	1,663	20,252	18,694	1,558
.16	Daniel Ash Management Project	164,343	163,959	163,575	163,191	162,807	162,422	162,038	161,653	161,269	160,886	160,501	160,118	1,946,762	1,797,011	149,751
.17	Smith Shield Water Project	566	565	564	563	562	561	559	557	557	555	554	552	6,715	6,199	516
.18	Underground Fuel Tank Replacement	6,012	5,964	5,919	5,873	5,825	5,780	5,733	5,686	5,639	5,594	5,548	5,500	69,073	63,760	5,313
.19	SO2 Allowances	(5,804)	(5,763)	(5,718)	(5,676)	(5,634)	(6,511)	(7,287)	(7,043)	(6,800)	(6,556)	(6,311)	(6,065)	(75,168)	0	(75,168)
2	Total Investment Projects - Recoverable Costs	713,241	710,459	707,496	705,402	703,297	700,456	697,714	696,102	694,790	694,084	693,617	700,102	8,416,756	2,487,700	5,929,056
3	Recoverable Costs Allocated to Energy	502,987	500,741	498,309	496,755	495,184	492,881	490,673	489,596	488,822	488,649	488,722	495,741	5,929,056		
4	Recoverable Costs Allocated to Demand	210,254	209,718	209,187	208,647	208,113	207,575	207,041	206,506	205,968	205,435	204,895	204,361	2,487,700		
5	Retail Energy Jurisdictional Factor	0.9637519	0.9665363	0.9684383	0.9695202	0.9689702	0.9687608	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763			
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)	485,094	484,323	482,919	481,951	480,154	477,818	474,206	473,984	472,744	472,156	471,876	479,060	5,736,285		
8	Jurisdictional Demand Recoverable Costs (C)	202,899	202,382	201,869	201,348	200,833	200,314	199,798	199,282	198,763	198,249	197,728	197,212	2,400,677		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	687,993	686,705	684,788	683,299	680,987	678,132	674,004	673,266	671,507	670,405	669,604	676,272	8,136,962		

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 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	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	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 ©	(239,115)	(239,448)	(239,780)	(240,113)	(240,445)	(240,777)	(241,110)	(241,442)	(241,775)	(242,108)	(242,440)	(242,773)	(243,106)	
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	88,252	87,920	87,587	87,255	86,922	86,589	86,257	85,924	85,591	
6	Average Net Investment		89,416	89,083	88,751	88,418	88,086	87,754	87,421	87,088	86,756	86,423	86,090	85,758	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		657	654	652	650	647	645	642	640	637	635	633	630	7,722
	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	332	333	333	333	333	333	333	333	333	3,991
	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	1,167	1,164	1,161	1,157	1,155	1,151	1,148	1,146	1,142	13,907
	a Recoverable Costs Allocated to Energy		1,177	1,173	1,170	1,167	1,164	1,161	1,157	1,155	1,151	1,148	1,146	1,142	13,907
	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	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	1,132	1,128	1,125	1,118	1,118	1,113	1,109	1,106	1,103	13,456
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	1,132	1,128	1,125	1,118	1,118	1,113	1,109	1,106	1,103	13,456

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 component 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 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	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)	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 ©	(8,788,768)	(8,883,091)	(8,977,413)	(9,071,736)	(9,166,059)	(9,260,382)	(9,354,705)	(9,449,028)	(9,543,350)	(9,637,674)	(9,731,997)	(9,826,321)	(9,920,646)	
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	15,557,734	15,463,412	15,369,089	15,274,766	15,180,443	15,086,120	14,991,797	14,897,475	14,803,151	14,708,828	14,614,504	14,520,179	
6	Average Net Investment		15,604,896	15,510,573	15,416,251	15,321,928	15,227,605	15,133,282	15,038,959	14,944,636	14,850,313	14,755,990	14,661,666	14,567,342	
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	79,433	79,434	953,193
	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	14,891	14,891	178,685
	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)		241,539	240,649	239,760	238,870	237,980	237,090	236,200	235,309	234,422	233,531	232,642	231,753	2,839,745
	a Recoverable Costs Allocated to Energy		241,539	240,649	239,760	238,870	237,980	237,090	236,200	235,309	234,422	233,531	232,642	231,753	2,839,745
	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	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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)		232,947	232,759	232,355	231,751	230,757	229,844	228,273	227,806	226,712	225,649	224,623	223,955	2,747,431
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)		232,947	232,759	232,355	231,751	230,757	229,844	228,273	227,806	226,712	225,649	224,623	223,955	2,747,431

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 component 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 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	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 ©	(702,014)	(709,352)	(716,692)	(724,030)	(731,370)	(738,708)	(746,048)	(753,386)	(760,726)	(768,064)	(775,404)	(782,743)	(790,083)	
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	1,418,519	1,411,181	1,403,841	1,396,502	1,389,162	
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	1,422,189	1,414,850	1,407,511	1,400,172	1,392,832	
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	7,083	7,082	7,083	7,083	7,083	84,991
	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	20,757	20,686	20,618	20,548	20,480	250,318
	a Recoverable Costs Allocated to Energy		21,239	21,172	21,101	21,034	20,963	20,896	20,824	20,757	20,686	20,618	20,548	20,480	250,318
	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	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	20,125	20,095	20,006	19,922	19,840	19,791	242,180
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	20,125	20,095	20,006	19,922	19,840	19,791	242,180

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 component 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 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	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	40,142	0	39,965	39,965	39,965	39,963	1,100,000	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	1,300,000	
	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)	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	17,596,359	
3	Less: Accumulated Depreciation ©	(4,563,638)	(4,616,601)	(4,669,564)	(4,722,527)	(4,775,490)	(4,828,454)	(4,881,416)	(4,934,379)	(4,987,343)	(5,040,305)	(5,093,268)	(5,146,232)	(5,201,308)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	40,142	40,142	80,107	120,072	160,037	200,000	0	
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	11,455,085	11,402,122	11,389,123	11,376,126	11,363,128	11,350,127	12,395,051	
6	Average Net Investment		11,706,240	11,653,277	11,600,314	11,547,351	11,494,387	11,461,495	11,428,604	11,395,623	11,382,625	11,369,627	11,356,628	11,872,589	
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	83,966	83,724	83,628	83,533	83,437	87,228	1,015,862
	b Debt Component (Line 6 x Debt Component x 1/12)		24,431	24,320	24,210	24,099	23,989	23,920	23,851	23,783	23,756	23,728	23,701	24,778	288,566
8	Investment Expenses														
	a Depreciation (E)		52,963	52,963	52,963	52,963	52,964	52,962	52,963	52,964	52,962	52,963	52,964	55,076	637,670
	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	161,090	160,780	160,471	160,346	160,224	160,102	167,082	1,942,098
	a Recoverable Costs Allocated to Energy		163,400	162,900	162,401	161,900	161,402	161,090	160,780	160,471	160,346	160,224	160,102	167,082	1,942,098
	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	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	156,167	155,384	155,354	155,072	154,816	154,584	161,460	1,878,946
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	156,167	155,384	155,354	155,072	154,816	154,584	161,460	1,878,946

(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 component 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 2003 - December 2003

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Crist 1-7, 6&7 Upgrade; Scholz 1; Smith 1 & 2; 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	(594)	2,825	373	0	0	0	22,396	25,000	150,000	50,000	50,000	
	b Clearings to Plant		128,310	(594)	0	3,198	0	0	0	0	0	0	100,000	197,396	
	c Retirements		0	533,256	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	729	0	(374)	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	4,026,954	4,224,350	
3	Less: Accumulated Depreciation ©	670,339	657,328	1,178,961	1,167,477	1,155,613	1,144,118	1,132,624	1,121,127	1,109,630	1,098,133	1,086,640	1,075,022	1,062,963	
4	CWIP - Non Interest Bearing	128,310	0	0	2,825	0	0	0	0	22,396	47,396	197,396	147,396	0	
5	Net Investment (Lines 2 - 3 + 4)	5,127,945	5,114,934	5,102,717	5,094,058	5,082,567	5,071,072	5,059,578	5,048,081	5,058,980	5,072,483	5,210,990	5,249,372	5,287,313	
6	Average Net Investment		5,121,440	5,108,826	5,098,388	5,088,313	5,076,820	5,065,325	5,053,830	5,053,531	5,065,732	5,141,737	5,230,181	5,268,343	
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	37,128	37,218	37,776	38,426	38,707	450,903
	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	10,547	10,572	10,731	10,915	10,995	128,082
8	Investment Expenses														
	a Depreciation (E)		13,011	12,352	11,484	11,490	11,495	11,494	11,497	11,497	11,497	11,493	11,618	12,059	140,987
	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)		62,717	61,940	60,973	60,884	60,780	60,671	60,565	60,563	60,678	61,391	62,350	63,152	736,664
	a Recoverable Costs Allocated to Energy		62,717	61,940	60,973	60,884	60,780	60,671	60,565	60,563	60,678	61,391	62,350	63,152	736,664
	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	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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)		60,486	59,909	59,090	59,070	58,935	58,817	58,533	58,632	58,682	59,319	60,201	61,027	712,701
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)		60,486	59,909	59,090	59,070	58,935	58,817	58,533	58,632	58,682	59,319	60,201	61,027	712,701

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 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) 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 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	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 ©	(76,138)	(78,185)	(80,233)	(82,280)	(84,327)	(86,374)	(88,423)	(90,469)	(92,516)	(94,565)	(96,612)	(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	847,114	845,067	843,020	840,971	838,925	836,878	834,829	832,782	830,735	828,687	
6	Average Net Investment		852,233	850,186	848,138	846,091	844,044	841,996	839,949	837,902	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	1,913	1,911	1,912	1,913	1,912	1,912	1,912	22,946
	b Amortization (F)		135	135	135	135	135	136	135	135	136	135	135	136	1,623
	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	10,049	10,030	10,010	9,993	9,971	9,953	9,936	9,914	9,893	9,876	119,773
	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	9,276	9,259	9,240	9,224	9,204	9,188	9,172	9,151	9,132	9,116	110,568
10	Energy Jurisdictional Factor		0.9637519	0.9665363	0.9684383	0.9695202	0.9689702	0.9687608	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	741	741	739	737	735	734	8,914
13	Retail Demand-Related Recoverable Costs (I)		8,985	8,970	8,952	8,935	8,917	8,901	8,882	8,867	8,851	8,831	8,813	8,797	106,701
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		9,733	9,720	9,701	9,683	9,664	9,646	9,623	9,608	9,590	9,568	9,548	9,531	115,615

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 component has been grossed up for taxes. The approved ROE is 12%.
(E) Part of PE 1007 depreciable at 2.5% annually, Pos 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 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	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 ©	(13,373)	(14,116)	(14,859)	(15,602)	(16,345)	(17,088)	(17,831)	(18,574)	(19,317)	(20,060)	(20,803)	(21,546)	(22,289)	
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)	229,570	228,827	228,084	227,341	226,598	225,855	225,112	224,369	223,626	222,883	222,140	221,397	220,654	
6	Average Net Investment		229,199	228,456	227,713	226,970	226,227	225,484	224,741	223,998	223,255	222,512	221,769	221,026	
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	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)		2,905	2,898	2,891	2,883	2,877	2,869	2,864	2,856	2,849	2,842	2,835	2,828	34,400
	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	2,648	2,643	2,637	2,630	2,623	2,617	2,610	31,750
10	Energy Jurisdictional Factor		0.9637519	0.9665363	0.9684383	0.9695202	0.9689702	0.9687608	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	210	211	2,561
13	Retail Demand-Related Recoverable Costs (I)		2,587	2,581	2,576	2,568	2,563	2,555	2,551	2,545	2,538	2,531	2,525	2,519	30,639
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,803	2,797	2,791	2,783	2,777	2,769	2,765	2,757	2,750	2,743	2,735	2,730	33,200

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 (a), 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) 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 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	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 ©	(297,961)	(301,112)	(304,263)	(307,415)	(310,566)	(313,717)	(316,867)	(320,018)	(323,169)	(326,319)	(329,471)	(332,622)	(335,773)	
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	605,547	602,396	599,244	596,093	592,942	589,792	586,641	583,490	580,340	577,188	574,037	570,886	
6	Average Net Investment		607,123	603,972	600,820	597,669	594,518	591,367	588,217	585,066	581,915	578,764	575,613	572,462	
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												0		
	a Depreciation (E)		2,946	2,947	2,947	2,947	2,947	2,946	2,946	2,946	2,946	2,947	2,947	2,947	35,359
	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)		8,879	8,848	8,820	8,789	8,760	8,729	8,701	8,670	8,639	8,612	8,581	8,552	104,580
	a Recoverable Costs Allocated to Energy		683	681	678	676	674	671	669	667	665	662	660	658	8,044
	b Recoverable Costs Allocated to Demand		8,196	8,167	8,142	8,113	8,086	8,058	8,032	8,003	7,974	7,950	7,921	7,894	96,536
10	Energy Jurisdictional Factor		0.9637519	0.9665363	0.9684383	0.9695202	0.9689702	0.9687608	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	650	647	646	643	640	637	636	7,784
13	Retail Demand-Related Recoverable Costs (I)		7,909	7,881	7,857	7,829	7,803	7,776	7,751	7,723	7,695	7,672	7,644	7,618	93,158
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,568	8,540	8,514	8,485	8,457	8,426	8,398	8,369	8,338	8,312	8,281	8,254	100,942

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 component 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 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 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)	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 ©	(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	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	228	228	226	226	225	224	2,742
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	2,959	2,952	2,942	2,933	2,924	2,914	35,573

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 component 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 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	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)	47,955	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 ©	(13,066)	(13,222)	(13,378)	(13,534)	(13,690)	(13,846)	(14,002)	(14,158)	(14,314)	(14,470)	(14,626)	(14,782)	(14,938)	
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	33,017	
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	33,095	
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	156	1,872
	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	468	5,715
	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	432	5,276
10	Energy Jurisdictional Factor		0.9637519	0.9665363	0.9684383	0.9695202	0.9689702	0.9687608	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	417	5,093
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		468	466	464	464	462	461	460	458	457	455	453	452	5,520

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 component 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 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	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 ©	(26,193)	(26,523)	(26,853)	(27,183)	(27,513)	(27,843)	(28,173)	(28,503)	(28,833)	(29,163)	(29,493)	(29,823)	(30,153)	
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	71,672	71,342	
6	Average Net Investment		75,137	74,807	74,477	74,147	73,817	73,487	73,157	72,827	72,497	72,167	71,837	71,507	
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	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)		1,039	1,036	1,032	1,030	1,026	1,023	1,020	1,017	1,014	1,011	1,008	1,004	12,260
	a Recoverable Costs Allocated to Energy		80	80	79	79	79	79	78	78	78	78	78	77	943
	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	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	75	76	75	75	75	74	912
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	984	982	978	975	972	969	11,833

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 component 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 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	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 ©	(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	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	44	45	44	43	43	43	531
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	575	574	571	569	567	565	6,907

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 compocnt 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 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	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 ©	(10,474)	(10,767)	(11,060)	(11,353)	(11,646)	(11,939)	(12,232)	(12,525)	(12,818)	(13,111)	(13,404)	(13,697)	(13,990)	
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	94,265	93,972	93,679	93,386	93,093	92,800	92,507	
6	Average Net Investment		95,877	95,584	95,291	94,998	94,705	94,412	94,119	93,826	93,533	93,240	92,947	92,654	
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	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)		1,197	1,194	1,192	1,189	1,187	1,184	1,180	1,178	1,175	1,173	1,170	1,167	14,186
	a Recoverable Costs Allocated to Energy		1,197	1,194	1,192	1,189	1,187	1,184	1,180	1,178	1,175	1,173	1,170	1,167	14,186
	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	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	1,148	1,140	1,140	1,136	1,133	1,130	1,128	13,724
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	1,148	1,140	1,140	1,136	1,133	1,130	1,128	13,724

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 component 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 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	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 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	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	2,051	2,049	2,042	2,034	2,028	2,024	24,670
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	26,623	26,558	26,486	26,414	26,344	26,275	319,928

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 component 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 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	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)	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 ©	(44,462)	(44,944)	(45,426)	(45,908)	(46,390)	(46,872)	(47,354)	(47,836)	(48,318)	(48,799)	(49,281)	(49,762)	(50,244)	
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	126,401	125,919	125,438	124,956	
6	Average Net Investment		130,497	130,015	129,533	129,051	128,569	128,087	127,605	127,123	126,642	126,160	125,679	125,197	
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	481	482	481	482	5,782
	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	1,675	1,672	1,666	1,663	20,252
	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	1,546	1,543	1,538	1,535	18,694
10	Energy Jurisdictional Factor		0.9637519	0.9665363	0.9684383	0.9695202	0.9689702	0.9687608	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	1,492	1,489	1,484	1,481	18,040
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,653	1,649	1,645	1,640	1,636	1,631	1,628	1,623	1,617	1,614	1,608	1,605	19,549

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 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	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 ©	(3,329,065)	(3,369,783)	(3,410,501)	(3,451,219)	(3,491,937)	(3,532,655)	(3,573,373)	(3,614,091)	(3,654,809)	(3,695,526)	(3,736,244)	(3,776,961)	(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	9,546,943	9,506,225	9,465,508	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	9,567,302	9,526,584	9,485,867	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	30,894	30,895	30,894	30,895	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	161,269	160,886	160,501	160,118	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	148,864	148,510	148,155	147,801	1,797,011
10	Energy Jurisdictional Factor		0.9637519	0.9665363	0.9684383	0.9695202	0.9689702	0.9687608	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	12,046	12,038	11,997	11,958	11,920	11,903	144,881
13	Retail Demand-Related Recoverable Costs (I)		146,394	146,053	145,710	145,368	145,026	144,683	144,342	143,998	143,657	143,315	142,972	142,631	1,734,149
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		158,586	158,251	157,904	157,547	157,170	156,795	156,388	156,036	155,654	155,273	154,892	154,534	1,879,030

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 component 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 Current Period Estimated 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	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 ©	(1,777)	(1,909)	(2,041)	(2,173)	(2,305)	(2,437)	(2,569)	(2,701)	(2,832)	(2,964)	(3,095)	(3,227)	(3,358)	
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	45,074	44,942	44,811	44,679	44,548	
6	Average Net Investment		46,063	45,931	45,799	45,667	45,535	45,403	45,271	45,140	45,008	44,877	44,745	44,614	
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	131	132	131	132	131	1,581
	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	557	557	555	554	552	6,715
	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	514	514	512	511	510	6,199
10	Energy Jurisdictional Factor		0.9637519	0.9665363	0.9684383	0.9695202	0.9689702	0.9687608	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	496	496	494	493	492	5,983
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		546	546	545	544	543	542	540	538	538	536	535	533	6,486

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 component 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 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	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 C	(339,828)	(344,749)	(349,669)	(354,590)	(359,511)	(364,431)	(369,352)	(374,272)	(379,193)	(384,113)	(389,034)	(393,955)	(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	103,329	98,408	93,488	88,567	83,647	78,726	73,806	68,885	63,964	59,044	
6	Average Net Investment		115,631	110,710	105,790	100,869	95,948	91,028	86,107	81,187	76,266	71,346	66,425	61,504	
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	4,921	4,921	4,920	4,921	4,920	4,921	4,920	4,921	4,921	4,920	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	5,919	5,873	5,825	5,780	5,733	5,686	5,639	5,594	5,548	5,500	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	5,464	5,421	5,377	5,335	5,292	5,249	5,205	5,164	5,121	5,077	63,760
10	Energy Jurisdictional Factor		0.9637519	0.9665363	0.9684383	0.9695202	0.9689702	0.9687608	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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	426	423	420	415	412	409	5,140
13	Retail Demand-Related Recoverable Costs (I)		5,356	5,312	5,273	5,231	5,189	5,148	5,107	5,065	5,023	4,983	4,942	4,899	61,528
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		5,802	5,756	5,714	5,670	5,623	5,579	5,533	5,488	5,443	5,398	5,354	5,308	66,668

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 component 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 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	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	216,362		0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	32,680	31,577	30,851	30,182	29,281	28,268	27,155	25,739	24,311	22,954	21,671	20,624	19,290	
	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	(650,061)	(644,706)	(639,351)	(633,997)	(628,642)	(623,288)	(812,453)	(785,255)	(758,057)	(730,860)	(703,662)	(676,464)	(649,267)	
3	Total Working Capital Balance	(617,381)	(613,129)	(608,500)	(603,815)	(599,361)	(595,020)	(785,298)	(759,516)	(733,746)	(707,906)	(681,991)	(655,840)	(629,977)	
4	Average Net Working Capital Balance		(615,255)	(610,815)	(606,158)	(601,588)	(597,191)	(690,159)	(772,407)	(746,631)	(720,826)	(694,948)	(668,916)	(642,908)	
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)	(5,675)	(5,485)	(5,296)	(5,106)	(4,915)	(4,723)	(58,540)
	b Debt Component (Line 4 x 3.5137% x 1/12)		(1,284)	(1,275)	(1,265)	(1,256)	(1,246)	(1,440)	(1,612)	(1,558)	(1,504)	(1,450)	(1,396)	(1,342)	(16,628)
6	Total Return Component (D)		(5,804)	(5,763)	(5,718)	(5,676)	(5,634)	(6,511)	(7,287)	(7,043)	(6,800)	(6,556)	(6,311)	(6,065)	(75,168)
7	Expenses														
	a Gains		(5,355)	(5,355)	(5,354)	(5,355)	(5,354)	(27,198)	(27,198)	(27,198)	(27,198)	(27,198)	(27,198)	(27,198)	(217,157)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		1,103	726	669	901	1,013	1,113	1,416	1,428	1,357	1,283	1,047	1,334	13,390
8	Net Expenses (E)		(4,252)	(4,629)	(4,685)	(4,454)	(4,341)	(26,085)	(25,782)	(25,770)	(25,841)	(25,915)	(26,151)	(25,864)	(203,767)
9	Total System Recoverable Expenses (Lines 6 + 7)		(10,056)	(10,392)	(10,403)	(10,130)	(9,975)	(32,596)	(33,069)	(32,813)	(32,641)	(32,471)	(32,462)	(31,929)	(278,935)
	a Recoverable Costs Allocated to Energy		(10,056)	(10,392)	(10,403)	(10,130)	(9,975)	(32,596)	(33,069)	(32,813)	(32,641)	(32,471)	(32,462)	(31,929)	(278,935)
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9637519	0.9665363	0.9684383	0.9695202	0.9689702	0.9687608	0.9657652	0.9674366	0.9664330	0.9655726	0.9648561	0.9656763	
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)	(10,051)	(10,082)	(9,828)	(9,672)	(31,600)	(31,999)	(31,766)	(31,567)	(31,375)	(31,343)	(30,854)	(269,795)
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)	(10,051)	(10,082)	(9,828)	(9,672)	(31,600)	(31,999)	(31,766)	(31,567)	(31,375)	(31,343)	(30,854)	(269,795)

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

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

ENVIRONMENTAL COST RECOVERY CLAUSE

DOCKET NO. 030007-EI

PREPARED *REVISED* EXHIBIT OF
SUSAN D. RITENOUR

PROJECTION FILING FOR THE PERIOD

JANUARY 2004 – DECEMBER 2004

NOVEMBER 12, 2003

GULF POWER

A SOUTHERN COMPANY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030007-EI EXHIBIT NO. Comp Ex 3
COMPANY/ Gulf P.
WITNESS. S.D. Ritenour
DATE: 11-12-03

Schedule 1P
Revised 11/12/03

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered

For the Projected Period
January 2004 - December 2004

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)	1,265,695	1,635,632	2,901,327
	b Projected Capital Projects (Schedule 3P, Lines 7, 8 & 9)	8,880,863	2,319,083	11,199,946
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	10,146,558	3,954,715	14,101,273
2	True-Up for Estimated Over/(Under) Recovery for the period January 2003 - December 2003 (Schedule 1E, Line 4)	134,262	74,901	209,163
3	Final True-Up for the period January 2002 - December 2002 (Schedule 1A, Line 3)	149,148	80,452	229,600
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2004 - December 2004 (Line 1c - Line 2 - Line 3)	9,863,148	3,799,362	13,662,510
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	9,870,249	3,802,098	13,672,347

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.

Schedule 2P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 - December 2004

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	290,000	370,000	5,500	0	0	0	0	124,374	0	0	0	0	789,874		789,874
.3 Title V	5,937	5,937	8,577	9,224	6,630	10,127	6,630	6,630	9,130	9,224	6,401	9,689	94,136		94,136
.4 Asbestos Fees	2,000	0	0	0	0	0	0	0	0	0	0	0	2,000	2,000	
.5 Emission Monitoring	27,810	28,815	39,627	37,576	51,889	62,844	51,344	32,344	42,344	36,481	34,684	43,210	488,968		488,968
.6 General Water Quality	22,569	24,830	26,253	25,731	28,908	33,406	29,283	25,880	26,082	27,604	31,259	38,850	340,655	340,655	
.7 Groundwater Contamination Investigation	77,345	74,177	75,260	77,185	86,357	72,928	72,031	74,419	73,526	78,379	87,549	72,987	922,143	922,143	
.8 State NPDES Administration	30,500	11,500	0	0	0	0	0	0	0	0	0	0	42,000	42,000	
.9 Lead and Copper Rule	140	140	1,900	160	160	1,910	160	160	1,910	190	200	1,970	9,000	9,000	
.10 Env Auditing/Assessment	417	417	417	417	417	417	417	417	417	417	417	413	5,000	5,000	
.11 General Solid & Hazardous Waste	15,702	15,696	16,982	19,392	16,521	17,330	16,504	16,506	17,331	20,294	17,722	19,146	209,126	209,126	
.12 Above Ground Storage Tanks	0	0	16,250	0	0	16,250	0	0	16,250	0	0	16,250	65,000	65,000	
.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	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,663	20,000		20,000
.18 SPCC Substation Project	0	0	0	0	10,000	25,000	30,000	25,000	10,000	0	0	0	100,000	100,000	
.19 So2 Allowances	(6,835)	(7,051)	(7,049)	(7,097)	(6,915)	(6,689)	(6,633)	(6,642)	(6,687)	(6,840)	(6,863)	(6,842)	(82,143)		(82,143)
2 Total of O & M Activities	467,252	526,128	185,384	164,255	195,634	235,190	201,403	300,755	191,970	167,416	173,036	197,336	3,005,759	1,694,924	1,310,835
3 Recoverable Costs Allocated to Energy	318,579	399,368	48,322	41,370	53,271	67,949	53,008	158,373	46,454	40,532	35,889	47,720	1,310,835		
4 Recoverable Costs Allocated to Demand	148,673	126,760	137,062	122,885	142,363	167,241	148,395	142,382	145,516	126,884	137,147	149,616	1,694,924		
5 Retail Energy Jurisdictional Factor	0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617			
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)	307,191	385,051	46,770	39,995	51,550	65,863	51,227	153,332	44,915	39,146	34,589	46,066	1,265,695		
8 Jurisdictional Demand Recoverable Costs (B)	143,472	122,326	132,267	118,586	137,383	161,391	143,204	137,401	140,426	122,445	132,349	144,382	1,635,632		
9 Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	450,663	507,377	179,037	158,581	188,933	227,254	194,431	290,733	185,341	161,591	166,938	190,448	2,901,327		

Notes:

(A) Line 3 x Line 5 x 1.0007 line loss multiplier
(B) Line 4 x Line 6

Schedule 3P
Revised 11/12/03

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 - December 2004

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	1,869	1,858	1,848	1,838	1,829	1,818	1,808	1,798	1,788	1,777	1,768	1,758	21,757	0	21,757
	.2 Crist 5, 6 & 7 Precipitator Projects	230,861	229,971	229,082	228,192	227,302	210,481	193,841	193,314	192,789	192,263	191,736	191,211	2,511,043	0	2,511,043
	.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	169,668	173,195	180,748	188,300	202,826	213,266	212,653	212,040	211,428	210,814	210,202	209,589	2,394,729	0	2,394,729
	.5 CEMs- Plant Crist, Scholz, Smith, and Daniel	63,575	63,525	63,474	63,423	63,372	63,322	63,248	63,142	63,232	63,528	63,824	64,079	761,744	0	761,744
	.6 Sub. Contam. Mobile Groundwater Treat. Sys.	9,855	9,836	9,817	9,798	9,778	9,759	9,740	9,720	9,701	9,681	9,662	9,642	116,989	107,989	9,000
	.7 Raw Water Well Flowmeters - Crist & Smith	2,821	2,814	2,808	2,800	2,794	2,786	2,779	2,772	2,765	2,758	2,751	2,744	33,392	30,824	2,568
	.8 *Crist Cooling Tower Cell*	8,523	8,493	8,463	8,432	8,404	8,373	8,345	8,314	8,285	8,254	8,224	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	490	536	582	659	714	712	710	708	705	704	701	700	7,921	7,311	610
	.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	1,640	1,636	1,631	1,626	1,622	1,617	1,613	1,608	19,599	18,091	1,508
	.16 Daniel Ash Management Project	158,240	157,856	157,472	157,088	156,704	156,320	155,935	155,551	155,167	154,783	154,399	154,015	1,873,530	1,729,413	144,117
	.17 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	5,314	5,269	5,222	5,176	5,129	5,084	5,036	4,990	4,943	62,388	57,589	4,799
	.19 Crist DEP Project	0	0	0	0	0	240,519	480,456	479,293	478,128	476,964	475,800	474,636	3,105,796	0	3,105,796
	.20 Crist Scrubber Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.21 Crist Stormwater Collection System	0	0	0	0	0	0	196	589	982	1,376	1,769	2,566	7,478	6,903	575
	.22 *Crist Common FTIR*	118	450	664	663	661	660	658	656	655	654	651	650	7,140	0	7,140
	.23 SO2 Allowances	(5,911)	(5,845)	(5,779)	(5,713)	(5,646)	(5,582)	(5,519)	(5,456)	(5,393)	(5,330)	(5,265)	(5,200)	(66,639)	0	(66,639)
2	Total Investment Projects - Recoverable Costs	701,097	703,466	709,745	715,835	728,883	962,368	1,184,573	1,181,954	1,179,534	1,177,316	1,175,102	1,173,255	11,593,128	2,403,149	9,189,979
3	Recoverable Costs Allocated to Energy	498,629	501,487	508,258	514,815	528,340	762,368	984,925	982,481	980,234	978,191	976,150	974,101	9,189,979		
4	Recoverable Costs Allocated to Demand	202,468	201,979	201,487	201,020	200,543	200,000	199,648	199,473	199,300	199,125	198,952	199,154	2,403,149		
5	Retail Energy Jurisdictional Factor	0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617			
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)	480,805	483,509	491,939	497,702	511,275	738,967	951,842	951,207	947,751	944,734	940,796	940,336	8,880,863		
8	Jurisdictional Demand Recoverable Costs (B)	195,385	194,914	194,439	193,988	193,528	193,004	192,664	192,495	192,328	192,159	191,992	192,187	2,319,083		
9	*Total Jurisdictional Recoverable Costs* for Investment Projects (Lines 7 + 8)	676,190	678,423	686,378	691,690	704,803	931,971	1,144,506	1,143,702	1,140,079	1,136,893	1,132,788	1,132,523	11,199,946		

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 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	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)	(243,106)	(244,172)	(245,238)	(246,304)	(247,370)	(248,436)	(249,502)	(250,568)	(251,634)	(252,700)	(253,766)	(254,832)	(255,898)	
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)	85,591	84,525	83,459	82,393	81,327	80,261	79,195	78,129	77,063	75,997	74,931	73,865	72,799	
6	Average Net Investment		85,058	83,992	82,926	81,860	80,794	79,728	78,662	77,596	76,530	75,464	74,398	73,332	
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 2.5042% 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	12,792
	c Dismantlemeat		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	21,757
	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	21,757
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		1,802	1,791	1,789	1,777	1,770	1,762	1,747	1,741	1,729	1,716	1,704	1,697	21,025
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)		1,802	1,791	1,789	1,777	1,770	1,762	1,747	1,741	1,729	1,716	1,704	1,697	21,025

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 2004 - December 2004

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	11,862,909	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	700,000	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	10,000	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	12,577,916	12,577,916	12,577,916	12,577,916	12,577,916	12,577,916	12,577,916	
3	Less: Accumulated Depreciation (C)	(9,920,646)	(10,014,969)	(10,109,292)	(10,203,616)	(10,297,939)	(10,392,262)	2,085,601	2,029,833	1,974,065	1,918,297	1,862,528	1,806,760	1,750,991	
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)	14,520,179	14,425,856	14,331,533	14,237,209	14,142,886	14,048,563	14,663,517	14,607,749	14,551,981	14,496,213	14,440,444	14,384,676	14,328,907	
6	Average Net Investment		14,473,018	14,378,695	14,284,371	14,190,048	14,095,725	14,356,040	14,635,633	14,579,865	14,524,097	14,468,329	14,412,560	14,356,792	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		106,333	105,640	104,947	104,254	103,561	105,474	107,528	107,118	106,709	106,299	105,889	105,479	1,269,231
	b Debt Component (Line 6 x 2.5042% x 1/12)		30,205	30,008	29,811	29,615	29,418	29,961	30,545	30,428	30,312	30,195	30,079	29,963	360,540
8	Investment Expenses														
	a Depreciation (E)		79,433	79,433	79,433	79,433	79,433	60,155	40,878	40,878	40,878	40,878	40,878	40,878	702,588
	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)		230,861	229,971	229,082	228,192	227,302	210,481	193,841	193,314	192,789	192,263	191,736	191,211	2,511,043
	a *Recoverable Costs Allocated to Energy*		230,861	229,971	229,082	228,192	227,302	210,481	193,841	193,314	192,789	192,263	191,736	191,211	2,511,043
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		222,609	221,727	221,727	220,606	219,960	204,020	187,330	187,161	186,400	185,687	184,792	184,583	2,426,602
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)		222,609	221,727	221,727	220,606	219,960	204,020	187,330	187,161	186,400	185,687	184,792	184,583	2,426,602

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 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	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)	(790,083)	(797,422)	(804,762)	(812,101)	(819,441)	(826,780)	(834,120)	(841,459)	(848,799)	(856,138)	(863,478)	(870,817)	(878,157)	
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)	1,389,162	1,381,823	1,374,483	1,367,144	1,359,804	1,352,465	1,345,125	1,337,786	1,330,446	1,323,107	1,315,767	1,308,428	1,301,088	
6	Average Net Investment		1,385,493	1,378,153	1,370,814	1,363,474	1,356,135	1,348,795	1,341,456	1,334,116	1,326,777	1,319,437	1,312,098	1,304,758	
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 2.5042% 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		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		19,680	19,612	19,620	19,531	19,483	19,449	19,323	19,292	19,198	19,111	19,003	18,968	232,270
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)		19,680	19,612	19,620	19,531	19,483	19,449	19,323	19,292	19,198	19,111	19,003	18,968	232,270

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 2004 - December 2004

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	853,567	853,567	853,567	853,569	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	4,714,270	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	1,020,000	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	211,300	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	19,990,629	19,990,629	19,990,629	19,990,629	19,990,629	19,990,629	19,990,629	19,990,629	
3	Less: Accumulated Depreciation (C)	(5,199,195)	(5,252,158)	(5,305,121)	(5,358,084)	(5,411,047)	(4,238,714)	(4,303,683)	(4,368,652)	(4,433,621)	(4,498,590)	(4,563,559)	(4,628,528)	(4,693,497)	
4	CWIP - Non Interest Bearing	1,300,000	1,300,000	2,153,567	3,007,134	3,860,701	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 - 3 + 4)	12,397,164	12,344,201	13,144,805	13,945,409	14,746,013	15,751,915	15,686,946	15,621,977	15,557,008	15,492,039	15,427,070	15,362,101	15,297,132	
6	Average Net Investment		12,370,683	12,744,503	13,545,107	14,345,711	15,248,964	15,719,431	15,654,462	15,589,493	15,524,524	15,459,555	15,394,586	15,329,617	
7	*Return on Average Net Investment*														
	a Equity Component Grossed Up For Taxes (D)		90,887	93,634	99,516	105,398	112,034	115,491	115,013	114,536	114,059	113,581	113,104	112,627	1,299,880
	b Debt Component (Line 6 x 2.5042% x 1/12)		25,818	26,598	28,269	29,939	31,825	32,806	32,671	32,535	32,400	32,264	32,129	31,993	369,247
8	Investment Expenses														
	a Depreciation (E)		52,963	52,963	52,963	52,963	58,967	64,969	64,969	64,969	64,969	64,969	64,969	64,969	725,602
	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)		169,668	173,195	180,748	188,300	202,826	213,266	212,653	212,040	211,428	210,814	210,202	209,589	2,394,729
	a Recoverable Costs Allocated to Energy		169,668	173,195	180,748	188,300	202,826	213,266	212,653	212,040	211,428	210,814	210,202	209,589	2,394,729
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		163,603	166,986	174,944	182,041	196,275	206,720	205,510	205,291	204,422	203,604	202,589	202,324	2,314,309
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)		163,603	166,986	174,944	182,041	196,275	206,720	205,510	205,291	204,422	203,604	202,589	202,324	2,314,309

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 2004 - December 2004

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, 1560
(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		6,999	6,999	6,999	6,999	6,999	7,005	0	0	43,750	43,750	43,750	43,750	
	b Clearings to Plant		0	0	0	0	0	0	42,000	0	0	0	0	175,000	
	c Retirements		0	0	0	0	0	0	32,500	0	0	0	0	200,000	
	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)	4,224,350	4,224,350	4,224,350	4,224,350	4,224,350	4,224,350	4,224,350	4,233,850	4,233,850	4,233,850	4,233,850	4,233,850	4,208,850	
3	Less: Accumulated Depreciation (C)	1,062,963	1,050,585	1,038,207	1,025,829	1,013,451	1,001,073	988,695	1,008,806	996,406	984,006	971,606	959,206	1,146,847	
4	CWIP - Non Interest Bearing	0	6,999	13,998	20,997	27,996	34,995	42,000	0	0	43,750	87,500	131,250	0	
5	Net Investment (Lines 2 - 3 + 4)	5,287,313	5,281,934	5,276,555	5,271,176	5,265,797	5,260,418	5,255,045	5,242,656	5,230,256	5,261,606	5,292,956	5,324,306	5,355,697	
6	Average Net Investment		5,284,624	5,279,245	5,273,866	5,268,487	5,263,108	5,257,732	5,248,851	5,236,456	5,245,931	5,277,281	5,308,631	5,340,002	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		38,826	38,787	38,747	38,708	38,668	38,629	38,563	38,472	38,542	38,772	39,003	39,233	464,950
	b Debt Component (Line 6 x 2.5042% x 1/12)		11,029	11,018	11,007	10,995	10,984	10,973	10,954	10,928	10,948	11,014	11,079	11,145	132,074
8	Investment Expenses														
	a Depreciation (E)		12,378	12,378	12,378	12,378	12,378	12,378	12,389	12,400	12,400	12,400	12,400	12,359	148,616
	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		1,342	1,342	1,342	1,342	1,342	1,342	1,342	1,342	1,342	1,342	1,342	1,342	16,104
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		63,575	63,525	63,474	63,423	63,372	63,322	63,248	63,142	63,232	63,528	63,824	64,079	761,744
	a Recoverable Costs Allocated to Energy		63,575	63,525	63,474	63,423	63,372	63,322	63,248	63,142	63,232	63,528	63,824	64,079	761,744
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		61,302	61,248	61,436	61,315	61,325	61,378	61,124	61,132	61,137	61,355	61,512	61,858	736,122
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)		61,302	61,248	61,436	61,315	61,325	61,378	61,124	61,132	61,137	61,355	61,512	61,858	736,122

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) 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 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	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)	(100,707)	(102,754)	(104,801)	(106,848)	(108,895)	(110,942)	(112,989)	(115,036)	(117,083)	(119,130)	(121,177)	(123,224)	(125,271)	
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	804,123	
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	805,147	
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 2.5042% 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	1,912	22,944
	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	9,836	9,817	9,798	9,778	9,759	9,740	9,720	9,701	9,681	9,662	9,642	116,989
	a Recoverable Costs Allocated to Energy		758	757	755	754	752	751	749	748	746	745	743	742	9,000
	b Recoverable Costs Allocated to Demand		9,097	9,079	9,062	9,044	9,026	9,008	8,991	8,972	8,955	8,936	8,919	8,900	107,989
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		731	730	731	729	728	728	724	724	721	720	716	716	8,698
13	Retail Demand-Related Recoverable Costs (I)		8,779	8,761	8,745	8,728	8,710	8,693	8,676	8,658	8,642	8,623	8,607	8,589	104,211
14	Total Juris. Recoverable Costs (Lines 12 + 13)		9,510	9,491	9,476	9,457	9,438	9,421	9,400	9,382	9,363	9,343	9,323	9,305	112,909

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

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 - December 2004

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: Accumulated Depreciation (C)	(22,289)	(23,032)	(23,775)	(24,518)	(25,261)	(26,004)	(26,747)	(27,490)	(28,233)	(28,976)	(29,719)	(30,462)	(31,205)	
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)	220,654	219,911	219,168	218,425	217,682	216,939	216,196	215,453	214,710	213,967	213,224	212,481	211,738	
6	Average Net Investment		220,283	219,540	218,797	218,054	217,311	216,568	215,825	215,082	214,339	213,596	212,853	212,110	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		1,618	1,613	1,608	1,602	1,597	1,591	1,586	1,580	1,575	1,569	1,564	1,558	19,061
	b Debt Component (Line 6 x 2.5042% 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	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)		2,821	2,814	2,808	2,800	2,794	2,786	2,779	2,772	2,765	2,758	2,751	2,744	33,392
	a Recoverable Costs Allocated to Energy		217	216	216	215	215	214	214	213	213	212	212	211	2,568
	b Recoverable Costs Allocated to Demand		2,604	2,598	2,592	2,585	2,579	2,572	2,565	2,559	2,552	2,546	2,539	2,533	30,824
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		209	208	209	208	208	207	207	206	206	205	204	204	2,481
13	Retail Demand-Related Recoverable Costs (I)		2,513	2,507	2,501	2,495	2,489	2,482	2,475	2,469	2,463	2,457	2,450	2,444	29,745
14	Total Juris. Recoverable Costs (Lines 12 + 13)		2,722	2,715	2,710	2,703	2,697	2,689	2,682	2,675	2,669	2,662	2,654	2,648	32,226

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) 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 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	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)	(335,773)	(338,925)	(342,076)	(345,228)	(348,379)	(351,531)	(354,682)	(357,834)	(360,985)	(364,137)	(367,288)	(370,439)	(373,590)	
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)	570,886	567,734	564,583	561,431	558,280	555,128	551,977	548,825	545,674	542,522	539,371	536,220	533,069	
6	Average Net Investment		569,310	566,159	563,007	559,856	556,704	553,553	550,401	547,250	544,098	540,947	537,796	534,645	
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	3,997	3,974	3,951	3,928	48,664
	b Debt Component (Line 6 x 2.5042% 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	2,947	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)		8,523	8,493	8,463	8,432	8,404	8,373	8,345	8,314	8,285	8,254	8,224	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	7,758	7,729	7,703	7,674	7,648	7,619	7,591	7,565	92,589
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		633	630	630	627	625	624	620	620	616	613	610	608	7,456
13	Retail Demand-Related Recoverable Costs (I)		7,592	7,566	7,539	7,511	7,487	7,459	7,434	7,406	7,380	7,352	7,325	7,300	89,351
14	*Total Juris. Recoverable Costs (Lines 12 + 13)*		8,225	8,196	8,169	8,138	8,112	8,083	8,054	8,026	7,996	7,965	7,935	7,908	96,807

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 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 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)	(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 2.5042% 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		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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	221	222	221	219	220	219	217	216	216	2,641
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 Juris. Recoverable Costs (Lines 12 + 13)		2,905	2,895	2,887	2,878	2,870	2,860	2,851	2,843	2,833	2,824	2,815	2,806	34,267

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 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	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	a Expenditures/Additions		5,000	5,000	5,000	5,000	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	20,000	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)	47,955	47,955	47,955	47,955	67,955	67,955	67,955	67,955	67,955	67,955	67,955	67,955	67,955	
3	Less: Accumulated Depreciation (C)	(14,938)	(15,094)	(15,250)	(15,406)	(15,594)	(15,815)	(16,036)	(16,257)	(16,478)	(16,699)	(16,920)	(17,141)	(17,362)	
4	CWIP - Non Interest Bearing	0	5,000	10,000	15,000	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 - 3 + 4)	33,017	37,861	42,705	47,549	52,361	52,140	51,919	51,698	51,477	51,256	51,035	50,814	50,593	
6	Average Net Investment		35,439	40,283	45,127	49,955	52,251	52,030	51,809	51,588	51,367	51,146	50,925	50,704	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		260	296	332	367	384	382	381	379	377	376	374	373	4,281
	b Debt Component (Line 6 x 2.5042% x 1/12)		74	84	94	104	109	109	108	108	107	107	106	106	1,216
8	Investment Expenses														
	a Depreciation (E)		156	156	156	188	221	221	221	221	221	221	221	221	2,424
	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)		490	536	582	659	714	712	710	708	705	704	701	700	7,921
	a Recoverable Costs Allocated to Energy		38	41	45	51	55	55	55	54	54	54	54	54	610
	b Recoverable Costs Allocated to Demand		452	495	537	608	659	657	655	654	651	650	647	646	7,311
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		37	40	44	49	53	53	53	52	52	52	52	52	589
13	Retail Demand-Related Recoverable Costs (I)		436	478	518	587	636	634	632	631	628	627	624	623	7,054
14	Total Juris. Recoverable Costs (Lines 12 + 13)		473	518	562	636	689	687	685	683	680	679	676	675	7,643

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 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	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)	(30,153)	(30,483)	(30,813)	(31,143)	(31,473)	(31,803)	(32,133)	(32,463)	(32,793)	(33,123)	(33,453)	(33,783)	(34,113)	
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)	71,342	71,012	70,682	70,352	70,022	69,692	69,362	69,032	68,702	68,372	68,042	67,712	67,382	
6	Average Net Investment		71,177	70,847	70,517	70,187	69,857	69,527	69,197	68,867	68,537	68,207	67,877	67,547	
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 2.5042% 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		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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	73	74	74	73	73	73	72	72	71	878
13	Retail Demand-Related Recoverable Costs (I)		893	890	886	884	881	878	874	873	870	867	865	862	10,523
14	Total Juris. Recoverable Costs (Lines 12 + 13)		967	964	961	957	955	952	947	946	943	939	937	933	11,401

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 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	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)	(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 2.5042% 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		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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	43	44	44	43	43	43	43	43	42	42	42	515
13	Retail Demand-Related Recoverable Costs (I)		520	519	518	515	515	512	511	510	508	507	504	504	6,143
14	Total Juris. Recoverable Costs (Lines 12 + 13)		563	562	562	559	558	555	554	553	551	549	546	546	6,658

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 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	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)	(13,990)	(14,283)	(14,576)	(14,869)	(15,162)	(15,455)	(15,748)	(16,041)	(16,334)	(16,627)	(16,920)	(17,213)	(17,506)	
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)	92,507	92,214	91,921	91,628	91,335	91,042	90,749	90,456	90,163	89,870	89,577	89,284	88,991	
6	Average Net Investment		92,361	92,068	91,775	91,482	91,189	90,896	90,603	90,310	90,017	89,724	89,431	89,138	
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 2.5042% 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		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
11	Demand Jurisdicional 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)		1,123	1,119	1,122	1,118	1,116	1,116	1,109	1,109	1,104	1,100	1,096	1,095	13,327
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)		1,123	1,119	1,122	1,118	1,116	1,116	1,109	1,109	1,104	1,100	1,096	1,095	13,327

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 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	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: Accumulated Depreciation (C)	(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 2.5042% 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		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)*		2,014	2,008	2,011	2,003	1,999	1,998	1,986	1,985	1,976	1,969	1,959	1,958	23,866
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 Juris. Recoverable Costs (Lines 12 + 13)		26,200	26,131	26,069	25,997	25,929	25,863	25,787	25,722	25,648	25,576	25,503	25,437	309,862

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 2004 - December 2004
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	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)	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)	(50,244)	(50,726)	(51,208)	(51,690)	(52,172)	(52,654)	(53,136)	(53,618)	(54,100)	(54,582)	(55,064)	(55,546)	(56,028)	
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)	124,956	124,474	123,992	123,510	123,028	122,546	122,064	121,582	121,100	120,618	120,136	119,654	119,172	
6	Average Net Investment		124,715	124,233	123,751	123,269	122,787	122,305	121,823	121,341	120,859	120,377	119,895	119,413	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		916	913	909	906	902	899	895	891	888	884	881	877	10,761
	b Debt Component (Line 6 x 2.5042% x 1/12)		260	259	258	257	256	255	254	253	252	251	250	249	3,054
8	Investment Expenses														
	a Depreciation (E)		482	482	482	482	482	482	482	482	482	482	482	482	5,784
	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	1,640	1,636	1,631	1,626	1,622	1,617	1,613	1,608	19,599
	a Recoverable Costs Allocated to Energy		128	127	127	127	126	126	125	125	125	124	124	124	1,508
	b Recoverable Costs Allocated to Demand		1,530	1,527	1,522	1,518	1,514	1,510	1,506	1,501	1,497	1,493	1,489	1,484	18,091
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		123	122	123	123	122	122	121	121	121	120	120	120	1,458
13	Retail Demand-Related Recoverable Costs (I)		1,476	1,474	1,469	1,465	1,461	1,457	1,453	1,448	1,445	1,441	1,437	1,432	17,458
14	Total Juris. Recoverable Costs (Lines 12 + 13)		1,599	1,596	1,592	1,588	1,583	1,579	1,574	1,569	1,566	1,561	1,557	1,552	18,916

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 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	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)	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)	(3,817,679)	(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 2.5042% 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		28,801	28,801	28,801	28,801	28,801	28,801	28,801	28,801	28,801	28,801	28,801	28,801	345,612
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		158,240	157,856	157,472	157,088	156,704	156,320	155,935	155,551	155,167	154,783	154,399	154,015	1,873,530
	a Recoverable Costs Allocated to Energy		12,172	12,143	12,113	12,084	12,054	12,025	11,995	11,965	11,936	11,906	11,877	11,847	144,117
	b Recoverable Costs Allocated to Demand		146,068	145,713	145,359	145,004	144,650	144,295	143,940	143,586	143,231	142,877	142,522	142,168	1,729,413
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		11,737	11,708	11,724	11,682	11,665	11,656	11,592	11,584	11,540	11,499	11,447	11,436	139,270
13	Retail Demand-Related Recoverable Costs (I)		140,958	140,616	140,274	139,932	139,590	139,247	138,905	138,563	138,221	137,879	137,536	137,195	1,668,916
14	Total Juris. Recoverable Costs (Lines 12 + 13)		152,695	152,324	151,998	151,614	151,255	150,903	150,497	150,147	149,761	149,378	148,983	148,631	1,808,186

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 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Consumptive Use-Shield Water Substitution Project
P.E. 1620
(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)	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)	(3,358)	(3,490)	(3,622)	(3,754)	(3,886)	(4,018)	(4,150)	(4,282)	(4,414)	(4,546)	(4,678)	(4,810)	(4,942)	
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)	44,548	44,416	44,284	44,152	44,020	43,888	43,756	43,624	43,492	43,360	43,228	43,096	42,964	
6	Average Net Investment		44,482	44,350	44,218	44,086	43,954	43,822	43,690	43,558	43,426	43,294	43,162	43,030	
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 2.5042% 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		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		40	40	41	41	41	41	41	41	41	41	40	40	488
13	Retail Demand-Related Recoverable Costs (I)		492	491	489	488	487	485	484	483	483	481	481	480	5,824
14	Total Juris. Recoverable Costs (Lines 12 + 13)		532	531	530	529	528	526	525	524	524	522	521	520	6,312

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 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	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)	(398,875)	(403,796)	(408,716)	(413,637)	(418,557)	(423,478)	(428,398)	(433,319)	(438,239)	(443,160)	(448,080)	(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	39,362	34,441	29,521	24,600	19,680	14,759	9,839	4,918	(2)	
6	Average Net Investment		56,584	51,663	46,743	41,822	36,902	31,981	27,061	22,140	17,220	12,299	7,379	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 2.5042% 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	4,920	4,921	4,920	4,921	4,920	4,921	4,920	4,921	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	
	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	5,314	5,269	5,222	5,176	5,129	5,084	5,036	4,990	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	4,905	4,864	4,820	4,778	4,734	4,693	4,649	4,606	4,563	57,589
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		405	401	399	395	392	390	385	382	378	374	370	367	4,638
13	Retail Demand-Related Recoverable Costs (I)		4,859	4,817	4,777	4,733	4,694	4,651	4,611	4,568	4,529	4,486	4,445	4,403	55,573
14	Total Juris. Recoverable Costs (Lines 12 + 13)		5,264	5,218	5,176	5,128	5,086	5,041	4,996	4,950	4,907	4,860	4,815	4,770	60,211

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 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	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	0	0	37,970,737	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	0	37,970,737	37,970,737	37,970,737	37,970,737	37,970,737	37,970,737	37,970,737	
3	*Less: Accumulated Depreciation (C)*	0	0	0	0	0	0	(61,702)	(185,107)	(308,512)	(431,917)	(555,322)	(678,727)	(802,132)	
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	37,909,035	37,785,630	37,662,225	37,538,820	37,415,415	37,292,010	37,168,605	
6	Average Net Investment		0	0	0	0	0	18,954,518	37,847,333	37,723,928	37,600,523	37,477,118	37,353,713	37,230,308	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		0	0	0	0	0	139,259	278,064	277,158	276,251	275,344	274,438	273,531	1,794,045
	b Debt Component (Line 6 x 2.5042% x 1/12)		0	0	0	0	0	39,558	78,987	78,730	78,472	78,215	77,957	77,700	509,619
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	61,702	123,405	123,405	123,405	123,405	123,405	123,405	802,132
	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	240,519	480,456	479,293	478,128	476,964	475,800	474,636	3,105,796
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	240,519	480,456	479,293	478,128	476,964	475,800	474,636	3,105,796
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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	233,136	464,318	464,037	462,284	460,650	458,568	458,184	3,001,177
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	233,136	464,318	464,037	462,284	460,650	458,568	458,184	3,001,177

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) PE 1199 qualified for AFUDC during construction; it will become part of the ECRC when the first phase of the project is moved to P-I-S in June 2004.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Scrubber Study
P.E. 1030
(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)	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	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	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		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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	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) 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 2004 - December 2004

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Storm Water Projects - Switchyard & Other Areas
P.E. 1272
(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	41,675	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 (C)	0	0	0	0	0	0	0	0	0	0	0	0	(406)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	41,675	83,350	125,025	166,700	208,375	0	
5	Net Investment (Lines 2 - 3 + 4)	0	0	0	0	0	0	0	41,675	83,350	125,025	166,700	208,375	249,594	
6	Average Net Investment		0	0	0	0	0	0	20,838	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	0	153	459	765	1,072	1,378	1,682	5,509
	b Debt Component (Line 6 x 2.5042% x 1/12)		0	0	0	0	0	0	43	130	217	304	391	478	1,563
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	0	196	589	982	1,376	1,769	2,566	7,478
	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	0	181	544	906	1,270	1,633	2,369	6,903
10	Energy Jurisdictional Factor		0.9635793	0.9635793	0.9635793	0.9635793	0.9635793	0.9635793	0.9635793	0.9635793	0.9635793	0.9635793	0.9635793	0.9635793	
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	14	43	73	102	131	190	553
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	175	525	874	1,226	1,576	2,286	6,662
14	Total Juris. Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	189	568	947	1,328	1,707	2,476	7,215

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) 3.9% 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 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	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	a Expenditures/Additions		25,000	27,500	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	52,500	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)	0	0	52,500	52,500	52,500	52,500	52,500	52,500	52,500	52,500	52,500	52,500	52,500	
3	Less: Accumulated Depreciation (C)	0	0	(85)	(256)	(427)	(598)	(769)	(940)	(1,111)	(1,282)	(1,453)	(1,624)	(1,795)	
4	CWIP - Non Interest Bearing	0	25,000	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 - 3 + 4)	0	25,000	52,415	52,244	52,073	51,902	51,731	51,560	51,389	51,218	51,047	50,876	50,705	
6	Average Net Investment		12,500	38,708	52,330	52,159	51,988	51,817	51,646	51,475	51,304	51,133	50,962	50,791	
7	Return on Average Net Investment														
	a Equity Component Grossed Up For Taxes (D)		92	284	384	383	382	381	379	378	377	376	374	373	4,163
	b Debt Component (Line 6 x 2.5042% x 1/12)		26	81	109	109	108	108	108	107	107	107	106	106	1,182
8	Investment Expenses														
	a Depreciation (E)		0	85	171	171	171	171	171	171	171	171	171	171	1,795
	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)		118	450	664	663	661	660	658	656	655	654	651	650	7,140
	a Recoverable Costs Allocated to Energy		118	450	664	663	661	660	658	656	655	654	651	650	7,140
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		114	434	643	641	640	640	636	635	633	632	627	627	6,902
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)		114	434	643	641	640	640	636	635	633	632	627	627	6,902

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

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 - December 2004
***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	19,290	18,429	17,784	17,137	16,538	15,757	14,750	13,687	12,633	11,625	10,769	9,936	9,083	
	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	(649,267)	(641,571)	(633,875)	(626,179)	(618,483)	(610,787)	(603,091)	(595,395)	(587,699)	(580,004)	(572,308)	(564,612)	(556,917)	
3	Total Working Capital Balance	(629,977)	(623,142)	(616,091)	(609,042)	(601,945)	(595,030)	(588,341)	(581,708)	(575,066)	(568,379)	(561,539)	(554,676)	(547,834)	
4	Average Net Working Capital Balance		(626,560)	(619,617)	(612,567)	(605,494)	(598,488)	(591,686)	(585,025)	(578,387)	(571,723)	(564,959)	(558,108)	(551,255)	
5	Return on Average Net Working Capital Balance														
	a Equity Component Grossed Up For Taxes (A)		(4,603)	(4,552)	(4,501)	(4,449)	(4,397)	(4,347)	(4,298)	(4,249)	(4,200)	(4,151)	(4,100)	(4,050)	(51,897)
	b Debt Component (Line 6 x 2.5042% x 1/12)		(1,308)	(1,293)	(1,278)	(1,264)	(1,249)	(1,235)	(1,221)	(1,207)	(1,193)	(1,179)	(1,165)	(1,150)	(14,742)
6	Total Return Component (D)		(5,911)	(5,845)	(5,779)	(5,713)	(5,646)	(5,582)	(5,519)	(5,456)	(5,393)	(5,330)	(5,265)	(5,200)	(66,639)
7	Expenses:														
	a Gains		(7,696)	(7,696)	(7,696)	(7,696)	(7,696)	(7,696)	(7,696)	(7,696)	(7,695)	(7,696)	(7,696)	(7,695)	(92,350)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		861	645	647	599	781	1,007	1,063	1,054	1,008	856	833	853	10,207
8	Net Expenses (E)		(6,835)	(7,051)	(7,049)	(7,097)	(6,915)	(6,689)	(6,633)	(6,642)	(6,687)	(6,840)	(6,863)	(6,842)	(82,143)
9	Total System Recoverable Expenses (Lines 6 + 8)		(12,746)	(12,896)	(12,828)	(12,810)	(12,561)	(12,271)	(12,152)	(12,098)	(12,080)	(12,170)	(12,128)	(12,042)	(148,782)
	a Recoverable Costs Allocated to Energy		(12,746)	(12,896)	(12,828)	(12,810)	(12,561)	(12,271)	(12,152)	(12,098)	(12,080)	(12,170)	(12,128)	(12,042)	(148,782)
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635793	0.9634764	0.9672145	0.9660819	0.9670238	0.9686274	0.9657343	0.9674915	0.9661858	0.9651214	0.9631079	0.9646617	
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)		(12,290)	(12,434)	(12,416)	(12,384)	(12,155)	(11,894)	(11,744)	(11,713)	(11,680)	(11,754)	(11,689)	(11,625)	(143,778)
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)		(12,290)	(12,434)	(12,416)	(12,384)	(12,155)	(11,894)	(11,744)	(11,713)	(11,680)	(11,754)	(11,689)	(11,625)	(143,778)

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 10 x 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 2004-December 2004

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 (RATA's) 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 further maintain compliance with Clean Air Act Amendment requirements. The existing equipment is approaching the end of their useful life, and will be retired upon replacement.

All RATA's 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 2004-December 2004

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.

Project-to-Date: $24,440,825

Progress Summary: In-Service. Part of the Unit 7 precipitator will be retired during the Spring outage as part of the Plant Crist FDEP- Gulf Ozone Agreement.

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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 2004-December 2004

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 Crist Unit 7 Low NOx burners will be replaced during 2003-2004.

Project-to-Date: $16,296,359

Progress Summary: In-Service.

Projections: $4,661,987

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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, 1560

Description:
This equipment is dilution extraction continuous emission monitors that measure concentrations of sulfur dioxide (SO2), carbon dioxide (CO2) and nitrogen oxides (NOx) in the flue gas.
Additionally, opacity and flow monitors were also installed. 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: $4,224,350

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 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 flow monitors and the shelter housing the gas analyzers on Plant Crist Units 6 & 7 (PE 1217) and replacement of the gas analyzers on Plant Daniel Units 1 & 2 (PE 1560). 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 $217,000 in 2004. 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 2004-December 2004

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 2004-December 2004

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 new environmental 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.

Project-to-Date: $242,943

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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 NPDES Permit.

Project-to-Date: $906,659

Progress Summary: In-Service.

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: ***Crist 1-5 Dechlorination***
PE 1248

Description:
State and Federal NPDES 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 2004-December 2004

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 first half of 2004.

Accomplishments:

Project-to-Date: $47,955

Progress Summary: Monitor wells are in service. The cap will be installed during the first half 2004.

Projections: $20,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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 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 2004-December 2004

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:
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 2004-December 2004

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Sodium Injection System
PE 1413

Description:
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 2004-December 2004

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) 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 2004-December 2004

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Waste Water Treatment Facility
PE 1466

Description:
The system replaced the existing septic tank system 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 includes aeration, chlorination, and dechlorination of the wastewater prior to discharging into a drain field. This project assures compliance with our industrial waste water permits requirements.

Accomplishments: *Compliance maintained.*

Project-to-Date: $175,200

Progress Summary: In-Service.

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Daniel Ash Management Project
PE 1535

Description:
Provide for a dry ash transport system, lining of the existing bottom ash pond, capping the existing flyash pond and constructing a dry ash storage cell. This project is required to comply with existing groundwater quality standards.

Accomplishments: No reportable exceedances have occurred since system installation.

Project-to-Date: $13,242,469

Progress Summary: In-Service.

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Consumptive Use - Shield Water Substitution Project
PE 1620

Description:
This project is a water conservation and consumptive use efficiency program to reduce the demand for groundwater and the potential for saltwater intrusion. Phase I of the project consists of adding pumps, piping, valves and controls at Plant Smith to reclaim water from the ash pond. 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, calling for a 25% reduction in the use of groundwater by the end of 2004.

Accomplishments:

Project-to-Date: $47,906

Progress Summary: In-Service.

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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 2004-December 2004

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist FDEP Agreement for Ozone Attainment
PE 1199

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 and relocate the Crist Unit 7 precipitator.

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.

Progress Summary: Gulf expects the first phase of this project to go in service in June 2004, at which time almost $38 million of capital investment will move into the ECRC.

Projections: $37,970,737 Construction on the project will continue through 2005.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Storm Water Project
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 skimmer pond where any potential spill would be captured, preventing the oil from reaching surface water.

Accomplishments:

Project-to-Date: $0

Progress Summary: Gulf expects to begin incurring costs for this project during the second half of 2004.

Projections: $250,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Common FTIR Monitor
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. The purchase of this instrument will enable Gulf Power to measure formaldehyde in stack emissions on units affected by EPA's new MACT standards for hazardous air pollutants under Section 112 of the Clean Air Act. Additionally, the monitor will be used to measure ammonia slip emissions required in the air construction permit on Crist Unit 7.

Accomplishments:

Project-to-Date: $0

Progress Summary: Gulf plans to purchase the FTIR in January/February 2004.

Projections: $52,500

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.1

Title: Sulfur/Ammonia

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 2004-December 2004

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: $789,874

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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.

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.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments.

Projections: $94,136

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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 2004-December 2004

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 the testing, development, and implementation of new Periodic Monitoring and Compliance Assurance Monitoring (CAM) associated with the CAAA of 1990.

Accomplishments:
All systems are in compliance.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections:
$488,968

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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 and also include surface and groundwater monitoring studies.

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: $340,655

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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 30 sites.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $922,143

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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: $42,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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: $9,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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: $5,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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: $209,126

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.12

Title: Above Ground Storage Tank Integrity and Secondary Containment Upgrades

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 will be required for Gulf's field erected above ground storage tanks in 2004.

Accomplishments:
Gulf has complied with all petroleum storage tank requirements.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments.

Projections: $65,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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 2004-December 2004

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.14

Title: Crist 4-7 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 2004-December 2004

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.15

Title: Mercury Emissions

Description:
This project refers to EPA requirements to analyze coal shipments for mercury and chlorine content.

Accomplishments:
Coal shipments are being analyzed as required.

Fiscal Expenditures: N/A

Progress Summary:
Sampling and analytical requirements are not expected in 2004.

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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 2004-December 2004

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 expected completion date for the GCOS project has been extended due to a delay in the final rule development by EPA. The goal of the project is to develop strategies for ozone ambient air attainment to supplement Florida's SIP submission to EPA for Escambia and Santa Rosa counties.

Projections: $20,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2004-December 2004

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. The SPCC Substation project will begin in May 2004.

Projections: $100,000

Schedule 6P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2004 - December 2004

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Jan - Dec. 2004 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	59.521838%	4,903,598,000	940,447.20	1.00486476	1.00530097	4,929,591,826	945,022.25	46.64256%	54.67725%
GS	61.623894%	294,062,000	54,473.55	1.00485887	1.00529775	295,619,867	54,738.23	2.79708%	3.16705%
GSD, GSDT, GSTOU	74.923957%	2,366,440,000	360,554.31	1.00470565	1.00516604	2,378,665,124	362,250.95	22.50634%	20.95917%
LP, LPT	86.403429%	2,055,355,000	271,551.22	0.98422595	0.98911989	2,032,992,512	267,267.76	19.23567%	15.46362%
PX, PXT, RTP, SBS	99.499138%	817,083,000	93,743.84	0.97443817	0.98057253	801,209,145	91,347.58	7.58084%	5.28520%
OS-I/II	247.068649%	101,916,000	4,708.91	1.00468934	1.00529485	102,455,630	4,730.99	0.96941%	0.27373%
OS-III	98.528325%	24,279,000	2,812.97	1.00511513	1.00526827	24,406,908	2,827.36	0.23093%	0.16359%
OS-IV	248.927520%	3,907,000	179.17	1.00240521	1.00541301	3,928,149	179.60	0.03717%	0.01039%
TOTAL		10,566,640,000	1,728,471.17			10,568,869,161	1,728,364.72	100.00000%	100.00000%

Notes:
(1) Average 12 CP load factor based on actual 2001 load research data
(2) Projected KWH sales for the period January 2004 - December 2004
(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
Revised 11/12/03

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2004 - December 2004

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	46.64256%	54.67725%	4,603,736	2,078,884	6,682,620	4,903,598,000	0.136
GS	2.79708%	3.16705%	276,079	120,414	396,493	294,062,000	0.135
GSD, GSDT, GSTOU	22.50634%	20.95917%	2,221,432	796,888	3,018,320	2,366,440,000	0.128
LP, LPT	19.23567%	15.46362%	1,898,609	587,942	2,486,551	2,055,355,000	0.121
PX, PXT, RTP, SBS	7.58084%	5.28520%	748,248	200,948	949,196	817,083,000	0.116
OS-I, OS-II	0.96941%	0.27373%	95,683	10,407	106,090	101,916,000	0.104
OS-III	0.23093%	0.16359%	22,793	6,220	29,013	24,279,000	0.119
OS-IV	0.03717%	0.01039%	3,669	395	4,064	3,907,000	0.104
TOTAL	100.00000%	100.00000%	$9,870,249	$3,802,098	$13,672,347	10,566,640,000	0.129

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 2004 - December 2004
(7) Col 5 / Col 6 x 100

EXHIBIT 1 (JP-1)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1A THROUGH 42-5A

OCTOBER 2002 - DECEMBER 2002
ESTIMATED/ACTUAL TRUE-UP

DOCUMENT NUMBER-DATE
03040 APR-1 8
FPSC-COMMISSION CLERK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030007-EI EXHIBIT NO. Comp. Ex. 4
COMPANY/ WITNESS: Progress Energy Fl. Jadier Portuondo, JP1, 2+3
DATE: 11-12-03

Form 42-1A

Progress Energy Florida, Inc.
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated/Actual True-Up Amount for the Period
October 2002 through December 2002

Line		
1	End of Period Actual True-Up for the Period October 2002 to December 2002 (Form 42-2A, Lines 5 +6)	(38,833)
2	Estimated/Actual True-Up Amount Approved for the Period October 2002 to December 2002	N/A
3	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2003 to December 2003 (Line 1 - Line 2)	(38,833)

Form 42-2A

Progress Energy Florida, Inc.
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated/Actual True-Up Amount for the Period
October 2002 through December 2002

End-of-Period True-Up Amount
(in Dollars)

Line		January 02	February 02	March 02	April 02	May 02	June 02	July 02	August 02	September 02	October 02	November 02	December 02	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
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)	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	0	0	0	0	0	0	0	0	0	0	0	38,833	38,833
	b. Capital Investment Projects (Form 42-7A, Line 9)	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
	c. Total Jurisdictional ECRC Costs	0	0	0	0	0	0	0	0	0	0	0	38,833	38,833
5	Over/Under Recovery (Line 3 - Line 4c)	0	0	0	0	0	0	0	0	0	0	0	(38,833)	(38,833)
6	Interest Provision (Form 42-3A, Line 10)	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Beginning Balance True-Up & Interest Provision	0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Deferred True-Up from January 2001 to December 2001	0	0	0	0	0	0	0	0	0	0	0	0	0
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)	0	0	0	0	0	0	0	0	0	0	0	(38,833)	(38,833)
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)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($38,833)	($38,833)

Form 42-3A

Progress Energy Florida, Inc.
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated/ActualTrue-Up Amount for the Period
October 2002 through December 2002

Interest Provision
(in Dollars)

Line		January 02	February 02	March 02	April 02	May 02	June 02	July 02	August 02	September 02	October 02	November 02	December 02	End of Period Total
1	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	0	0	0	0	0	0	0	0	0	0	0	(38,833)	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	0	0	0	0	0	0	0	0	0	0	0	(38,833)	
4	Average True-Up Amount (Line 3 x 1/2)	0	0	0	0	0	0	0	0	0	0	0	(19,417)	
5	Interest Rate (First Day of Reporting Business Month)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Interest Rate (First Day of Subsequent Business Month)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Average Interest Rate (Line 7 x 1/2)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
10	Interest Provision for the Month (Line 4 x Line 9)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Form 42-4A

Progress Energy Florida, Inc.
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated/Actual True-Up Amount for the Period
October 2002 through December 2002

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	Substation Environmental Investigation, Remediation, and Pollution Prevention	26,011	36,000	(9,989)	-27.7%
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	38,285	0	38,285	100.0%
2	Total O&M Activities	39,296	11,000	28,296	257.2%
3	Recoverable Costs Allocated to Energy	0	0	0	0.0%
4	Recoverable Costs Allocated to Demand	39,296	11,000	28,296	257.2%

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)

Form 42-5A

Progress Energy Florida, Inc.
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated/Actual Period Amount
October 2002 through December 2002

O&M Activities
(in Dollars)

Line		January 02	February 02	March 02	April 02	May 02	June 02	July 02	August 02	September 02	October 02	November 02	December 02	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	0	0	0	0	0	0	0	0	0	0	0	26,011	26,011	$26,011	0
	f(a) Substation Environmental Investigation, Remediation, and Pollution Prevention - Costs included in Base Rates	0	0	0	0	0	0	0	0	0	0		(25,000)	(25,000)	($25,000)	0
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	0	0	0	0	0	0	0	0	0	0	0	38,285	38,285	38,285	0
2	Total of O&M Activities	0	0	0	0	0	0	0	0	0	0	0	39,296	39,296	$39,296	$0
3	*Recoverable Costs Allocated to Energy - Transm*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*		
	Recoverable Costs Allocated to Energy - Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0		
4	Recoverable Costs Allocated to Demand - Transm	0	0	0	0	0	0	0	0	0	0	0	1,011	1,011		
	Recoverable Costs Allocated to Demand - Distrib	0	0	0	0	0	0	0	0	0	0	0	38,285	38,285		
5	Retail Transmission Energy Jurisdictional Factor	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.9729000	0.9728000	0.9761000			
	Retail Distribution Energy Jurisdictional Factor	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.9729000	0.9728000	0.9761000			
6	Retail Transmission Demand Jurisdictional Factor	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.72115000	0.72115000	0.72115000			
	Retail Distribution Demand Jurisdictional Factor	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.9952900	0.9952900	0.9952900			
7	Jurisdictional Energy Recoverable Costs - Transm	0	0	0	0	0	0	0	0	0	0	0	0	0		
	Jurisdictional Energy Recoverable Costs - Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0		
8	Jurisdictional Demand Recoverable Costs - Transm	0	0	0	0	0	0	0	0	0	0	0	729	729		
	Jurisdictional Demand Recoverable Costs - Distrib	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*38,104*	*38,104*		
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$38,833	$38,833		

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

FORM 42-6A

NOT USED

FORM 42-7A

NOT USED

FORM 42-8A

NOT USED

ECRC - 2002

Month posted	Vendor	Invoice Date	Invoice #	Work Done	Amount	T or D	Purpose
Dec	SWS	11/26/2002	24365	11/04/2002	18,512.86	T	Emergency response to petrolem spill at Curlew Substation
	SWS	12/13/2002	24521	12/04/2002	441.00	T	Emergency response to petrolem spill at Curlew Substation
Dec - Accr	Pike	01/03/2003	457610	12/29/2002	3,005.00	D	Oily dirt removal from transformers in the Apopka area
Dec - Accr	Pike	01/03/2003	458737		3,005.00	D	**Accrual estimate per Daryl O'Cain - Actual invoice came in at $3,473.28**
	Viasys	12/14/2002	105065-C	12/12/2002	1,254.00	D	Oily dirt removal from transformers in the Jamestown area
	Viasys	12/21/2002	105076-C	12/16/2002	864.00	D	Oily dirt removal from transformers in the Jamestown area
	Viasys	12/21/2002	105077-C	12/17/2002	2,996.00	D	Oily dirt removal from transformers in the Jamestown area
Dec-Accr	Viasys				2,877.00	D	**Accrual estimate per Daryl O'Cain - A/P has not authorized payment**
	SWS	11/14/2002	24239	11/09/2002	1,679.00	D	Emergency response to non-pcb transformer oil spill - Winter Pk
	US Filter	12/02/2002	9903737	11/25/2002	7,865.40	D	Disposal of oily dirt related to TRIP program
	US Filter	11/15/2002	71052721	10/08/2002	1,100.00	D	Analysis of oily dirt related to TRIP program - various spill sites
Dec	Kent				2,106.04	D	See attached documentation provided by Kent Hedrick
	Kent				498.00	T	See attached documentation provided by Kent Hedrick
	Other labor			12/04/2002	6,559.59	T	Overtime to clean up Curlew Substation
	Viasys	10/19/2002	607175	10/16/2002	1,848.00	D	Oily dirt removal from transformers in the Tarpon Springs area
	Viasys	10/19/2002	507781	10/17/2002	1,868.00	D	Oily dirt removal from transformers in the Clearwater area
	Viasys	10/26/2002	607176	10/19/2002	1,536.00	D	Oily dirt removal from transformers in the 7 Springs area
	Viasys	10/19/2002	507810	10/21/2002	2,867.00	D	Oily dirt removal from transformers in the St. Petersburg area
	Viasys	10/19/2002	507810	10/22/2002	3,243.75	D	Oily dirt removal from transformers in the St. Petersburg area
	55 Gl Blk/W				170.59	D	Transformer oil leak repair
					64,296.23		
					(64,296.23)		
					-		

	Totals on Sch	
Trans	26,011.23	**20031194**
Distr	38,285.00	**20032671**
	64,296.23	

Form Appendix

EXHIBIT 1 (JP-1)

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

JANUARY 2003 - DECEMBER 2003
Calculation of the Current Period Estimated/Actual Amount

Exhibit ____ (JP-1)
Progress Energy Florida
Docket No. 030007-EI
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Form 42-1E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 through December 2003
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$ (10,795,230)
2	Interest Provision (Form 42-2E, Line 6)	(24,270)
3	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4	Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2004 to December 2004 (Lines 1 + 2 + 3)	$ (10,819,500)

Exhibit ____ (JP-1)
Progress Energy Florid
Docket No. 030007-E
Page 2 of 1

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

Form 42
Schedule 2E

End-of-Period True-Up Amount
(in Dollars)

Line	Description	January 03	February 03	March 03	April 03	May 03	June 03	July 03	August 03	September 03	October 03	November 03	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	$371,639	$371,639	$371,639	$371,639	$371,639	$4,459,665
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	371,639	371,639	371,639	371,639	371,639	4,459,665
4	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5E, Line 9)	7,100	93,932	89,177	400,755	520,349	1,830,170	1,254,431	2,205,460	2,205,459	2,206,345	2,208,345	2,208,345	15,231,868
	b. Capital Investment Projects (Form 42-7E, Line 9)	0	0	0	0	0	0	0	0	0	1,737	5,114	16,176	23,027
	c. Total Jurisdictional ECRC Costs	7,100	93,932	89,177	400,755	520,349	1,830,170	1,254,431	2,205,460	2,205,459	2,210,082	2,213,459	2,224,521	15,254,895
5	Over/(Under) Recovery (Line 3 - Line 4c)	371,005	262,605	212,923	(74,961)	(147,200)	(1,401,173)	(817,643)	(1,833,821)	(1,833,820)	(1,838,443)	(1,841,820)	(1,852,882)	(10,795,230)
6	Interest Provision (Form 42-3E, Line 10)	157	487	709	764	661	(103)	(1,039)	(2,166)	(3,639)	(5,166)	(6,698)	(8,237)	(24,270)
7	Beginning Balance True-Up & Interest Provision	0	371,162	634,254	847,886	773,689	627,150	(774,126)	(1,592,808)	(3,428,795)	(5,266,254)	(7,109,863)	(8,958,381)	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)	(3,467,628)	(5,305,087)	(7,148,696)	(8,997,214)	(10,858,333)	(10,858,333)
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)	($3,467,628)	($5,305,087)	($7,148,696)	($8,997,214)	($10,858,333)	($10,858,333)

Exhibit ____ (JP-1)
Progress Energy Florida
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Form 42-3E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

Interest Provision
(in Dollars)

Line	Description	January 03	February 03	March 03	April 03	May 03	June 03	July 03	August 03	September 03	October 03	November 03	December 03	End of Period Total
1	Beginning True-Up Amount (Form 42-2E, Line 7 + 7a + 10)	($38,833)	$332,329	$595,421	$809,053	$734,856	$588,317	($812,959)	($1,631,641)	($3,467,628)	($5,305,087)	($7,148,696)	($8,997,214)	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	332,172	594,934	808,344	734,092	587,656	(812,856)	(1,630,602)	(3,465,462)	(5,301,448)	(7,143,530)	(8,990,516)	(10,850,096)	
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)	(5,097,103)	(8,769,076)	(12,448,617)	(16,139,212)	(19,847,310)	
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)	(2,548,552)	(4,384,538)	(6,224,309)	(8,069,606)	(9,923,655)	
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%	1.00%	1.00%	1.00%	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%	1.00%	1.00%	1.00%	1.00%	1.00%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	2.56%	2.52%	2.43%	2.37%	2.40%	2.21%	2.05%	2.05%	2.00%	2.00%	2.00%	2.00%	
8	Average Interest Rate (Line 7 x 1/2)	1.280%	1.260%	1.215%	1.185%	1.200%	1.105%	1.025%	1.025%	1.000%	1.000%	1.000%	1.000%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.107%	0.105%	0.101%	0.099%	0.100%	0.092%	0.085%	0.085%	0.083%	0.083%	0.083%	0.083%	
10	Interest Provision for the Month (Line 4 x Line 9)	$157	$487	$709	$764	$661	($103)	($1,039)	($2,166)	($3,639)	($5,166)	($6,698)	($8,237)	($24,270)

EXHIBIT ____ (JP-1)
Progress Energy Florida
Docket No. 030007-EI
Page 4 of 12

Form 42 4E

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

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	473,260	50,000	423,260	847%
1a	Substation Environmental Investigation, Remediation, and Pollution Prevention - Costs	(25,000)	(25,000)	0	0%
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	14,970,455	4,074,000	10,896,455	267%
3a	Pipeline Integrity Management	10,000	0	10,000	100%
4	Above Ground Tank Secondary Containment	0	0	0	0%
2	Total O&M Activities	15,428,715	4,099,000	11,329,715	276%
3	Recoverable Costs Allocated to Energy	0	0	0	0%
4	Recoverable Costs Allocated to Demand	15,428,715	4,099,000	11,329,715	276%

Notes:

Column (1) is the End of Period Totals on Form 42-5E
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Exhibit ____ (JP-1
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Docket No. 030007-E
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Form 42-5E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

O&M Activities
(in Dollars)

Line	Description	January 03	February 03	March 03	April 03	May 03	June 03	July 03	August 03	September 03	October 03	November 03	December 03	End of Period Total
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)	(18,798)	30,107	30,107	30,107	30,107	30,107	473,260
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)	(2,084)	(2,084)	(2,084)	(2,084)	(25,000)
2	Distribution System Environmental Investigation, Remediation, and Pollution	3,566	75,356	45,663	265,885	486,038	1,840,496	1,275,496	2,195,591	2,195,591	2,195,591	2,195,591	2,195,591	14,970,455
3a	Pipeline Integrity Management, Review/Update Plan and Risk Assessments	0	0	0	0	0	0	0	0	0	3,333	3,333	3,334	10,000
4	Above Ground Tank Secondary Containment	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total of O&M Activities	8,489	101,608	106,301	454,643	536,790	1,838,198	1,254,616	2,223,615	2,223,614	2,226,947	2,226,947	2,226,948	15,428,715
3	Recoverable Costs Allocated to Energy - Transm	0	0	0	0	0	0	0	0	0	0	0	0	0
	Recoverable Costs Allocated to Energy - Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0
	Recoverable Costs Allocated to Energy - Production	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)	(20,881)	28,024	28,023	28,023	28,023	28,023	448,260
	Recoverable Costs Allocated to Demand - Distrib	3,566	75,356	45,663	265,885	486,038	1,840,496	1,275,496	2,195,591	2,195,591	2,195,591	2,195,591	2,195,591	14,970,455
	Recoverable Costs Allocated to Demand - Production	0	0	0	0	0	0	0	0	0	3,333	3,333	3,334	10,000
5	Retail Transmission Energy Jurisdictional Factor	0.98400	0.97430	0.97540	0.97570	0.98000	0.97680	0.97770	0.97770	0.97770	0.97770	0.97770	0.97770	
	Retail Distribution Energy Jurisdictional Factor	0.98400	0.97430	0.97540	0.97570	0.98000	0.97680	0.97770	0.97770	0.97770	0.97770	0.97770	0.97770	
	Retail Production Energy Jurisdictional Factor	0.98400	0.97430	0.97540	0.97570	0.98000	0.97680	0.97770	0.97770	0.97770	0.97770	0.97770	0.97770	
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	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	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
	Jurisdictional Energy Recoverable Costs - Distrib (A)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jurisdictional Energy Recoverable Costs - Production (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)	20,210	20,209	20,209	20,209	20,209	323,264
	Jurisdictional Demand Recoverable Costs - Distrib (B)	3,549	75,001	45,446	264,633	483,749	1,831,827	1,269,489	2,185,250	2,185,250	2,185,250	2,185,250	2,185,250	14,899,948
	Jurisdictional Demand Recoverable Costs - Production (B)	0	0	0	0	0	0	0	0	0	2,886	2,886	2,886	8,658
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	$2,205,460	$2,205,459	$2,208,345	$2,208,345	$2,208,345	$15,231,868

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

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Form 42 6E

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)

Calculation of the Current Period Estimated/Actual Amount

January 2003 to December 2003

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	18,111	0	18,111	100%
	4a Above Ground Tank Secondary Containment - Turner CT's	5,153	0	5,153	100%
	4b Above Ground Tank Secondary Containment - Bartow CT's	923	0	923	100%
	4c Above Ground Tank Secondary Containment - Crystal River 1 & 2	2,936	0	2,936	100%
2	Total Capital Investment Activities	27,123	0	27,123	100%
3	Recoverable Costs Allocated to Energy	0	0	0	0%
4	Recoverable Costs Allocated to Demand	27,123	0	27,123	100%

Notes:

Column (1) is the End of Period Totals on Form 42-7E
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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PROGRESS ENERGY FLORIDA

Form 42-7E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

Capital Investment Projects-Recoverable Costs
(In Dollars)

Line	Description	January 03	February 03	March 03	April 03	May 03	June 03	July 03	August 03	September 03	October 03	November 03	December 03	End of Period Total
1	Description of Investment Projects (A)													
	3b Pipeline Integrity Management - Bartow/Anclote Pipeline	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,514	$4,658	$11,939	$18,111
	4a Above Ground Tank Secondary Containment - Turner CTs	0	0	0	0	0	0	0	0	0	0	0	5,153	5,153
	4b Above Ground Tank Secondary Containment - Bartow CTs	0	0	0	0	0	0	0	0	0	0	0	923	923
	4c Above Ground Tank Secondary Containment - Crystal River 1&2	0	0	0	0	0	0	0	0	0	444	1,127	1,365	2,936
2	Total Investment Projects - Recoverable Costs	0	0	0	0	0	0	0	0	0	1,958	5,785	19,380	27,123
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	444	1,127	1,365	2,936
	Recoverable Costs Allocated to Demand - Production - Intermediate	0	0	0	0	0	0	0	0	0	1,514	4,658	11,939	18,111
	Recoverable Costs Allocated to Demand - Production - Peaking	0	0	0	0	0	0	0	0	0	0	0	6,076	6,076
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	0.0000000	0.0000000	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	426	1,081	1,310	2,817
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	0	0	0	0	0	0	0	0	0	1,311	4,033	10,336	15,679
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	0	0	0	0	0	0	0	0	0	0	0	4,530	4,530
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,737	$5,114	$16,176	$23,027

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
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

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	January 03	February 03	March 03	April 03	May 03	June 03	July 03	August 03	September 03	October 03	November 03	December 03	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$338,152	
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	651,842	
	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	$0	0	0	0	0	0	0	0	0	0	0	0	989,994	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(2,508)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	313,690	651,842	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	313,690	651,842	987,486	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	156,845	482,766	819,664	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	0	0	0	0	0	1,089	3,351	5,690	$10,130
	b. Debt Component (Line 6 x 3.25% x 1/12)		0	0	0	0	0	0	0	0	0	425	1,307	2,220	3,952
8	Investment Expenses														
	a. Depreciation (Line 2 x 3.04% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	2,508	2,508
	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	N/A
	d. Property Taxes (D)		0	0	0	0	0	0	0	0	0	0	0	1,521	1,521
	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	1,514	4,658	11,939	16,111
	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	1,514	4,658	11,939	16,111
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 (Intermediate)	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.8657400	0.8657400	0.8657400	
12	Retail Energy-Related Recoverable Costs (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	1,311	4,033	10,336	15,679
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,311	$4,033	$10,336	$15,679

Notes:
(A) Lines 6 x 8.3300% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 5.12%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 1992 Rate Case (Order No. PSC-92-1197-FOF-EI).
(B) Line 9a x Line 10
(C) Line 9b x Line 11
(D) Lines 2 + 3 x 89% @ .0183361 x 1/12 + 11% @ .0196598 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported.

Source:
Lines 7a,7b Based on 1992 Rate Case (Order No. PSC-92-1197-FOF-EI)
Lines 8a,8b Based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI)
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)
Line 8d Based on 2002 Actual Property Tax Millage Rate

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to 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	January 03	February 03	March 03	April 03	May 03	June 03	July 03	August 03	September 03	October 03	November 03	December 03	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$502,700	
	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	$0	0	0	0	0	0	0	0	0	0	0	0	502,700	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(1,864)	
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	500,836	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	250,418	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	0	0	0	0	0	0	0	1,738	$1,738
	b. Debt Component (Line 6 x 3.25% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	678	678
8	Investment Expenses														
	a. Depreciation (Line 2 x 4.45% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	1,864	1,864
	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 (Lines 2 + 3 x .020912 x 1/12)		0	0	0	0	0	0	0	0	0	0	0	873	873
	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	5,153	5,153
	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	5,153	5,153
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 (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	3,842	3,842
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,842	$3,842

Notes:
(A) Lines 6 x 8.3300% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 5.12%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 1992 Rate Case (Order No. PSC-92-1197-FOF-EI).
(B) Line 9a x Line 10
(C) Line 9b x Line 11

Source:
Lines 7a,7b Based on 1992 Rate Case (Order No. PSC-92-1197-FOF-EI)
Lines 8a,8b Based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI)
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)
Line 8d Based on 2002 Actual Property Tax Millage Rate

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to 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	January 03	February 03	March 03	April 03	May 03	June 03	July 03	August 03	September 03	October 03	November 03	December 03	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$91,900	
	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	$0	0	0	0	0	0	0	0	0	0	0	0	91,900	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(341)	
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	91,559	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	45,780	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	0	0	0	0	0	0	0	318	$318
	b. Debt Component (Line 6 x 3.25% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	124	124
8	Investment Expenses														
	a. Depreciation (Line 2 x 4.45% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	341	341
	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 (Lines 2 + 3 x .018338 x 1/12)		0	0	0	0	0	0	0	0	0	0	0	140	140
	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	923	923
	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	923	923
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 (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	688	688
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$688	$688

Notes:
(A) Lines 6 x 8.3300% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 5.12%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 1992 Rate Case (Order No. PSC-92-1197-FOF-EI).
(B) Line 9a x Line 10
(C) Line 9b x Line 11

Source:
Lines 7a,7b Based on 1992 Rate Case (Order No. PSC-92-1197-FOF-EI)
Lines 8a,8b Based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI)
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)
Line 8d Based on 2002 Actual Property Tax Millage Rate

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to 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	January 03	February 03	March 03	April 03	May 03	June 03	July 03	August 03	September 03	October 03	November 03	December 03	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,000	$50,000	$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	$0	0	0	0	0	0	0	0	0	0	50,000	100,000	100,000	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	(127)	(380)	(633)	
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	49,873	99,620	99,367	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	24,937	74,747	99,493	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	0	0	0	0	0	173	519	691	$1,383
	b. Debt Component (Line 6 x 3.25% x 1/12)		0	0	0	0	0	0	0	0	0	68	202	269	539
8	Investment Expenses														
	a. Depreciation (Line 2 x 3.04% x 1/12)		0	0	0	0	0	0	0	0	0	127	253	253	633
	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 (Lines 2 + 3 x .018338 x 1/12)		0	0	0	0	0	0	0	0	0	76	152	152	380
	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	444	1,127	1,365	2,936
	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	444	1,127	1,365	2,936
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 (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	426	1,081	1,310	2,817
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$426	$1,081	$1,310	$2,817

Notes:
(A) Lines 6 x 8.3300% x 1/12. Based on ROE of 12.00%, equity component of capital structure of 5.12%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 1992 Rate Case (Order No. PSC-92-1197-FOF-EI).
(B) Line 9a x Line 10
(C) Line 9b x Line 11

Source:
Lines 7a,7b Based on 1992 Rate Case (Order No. PSC-92-1197-FOF-EI)
Lines 8a,8b Based on 1997 Depreciation Study (Order No. PSC-98-1723-FOF-EI)
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)
Line 8d Based on 2002 Actual Property Tax Millage Rate

Form Appendix

EXHIBIT ___ (JP-1)
(Revised 9/05/03)

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

JANUARY 2003 - DECEMBER 2003
Calculation of the Current Period Estimated/Actual Amount
Actuals for Period January through July 2003
Estimated for Period August through December 2003

PROGRESS ENERGY FLORIDA

Form 42-1E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 through December 2003
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$ (10,795,865)
2	Interest Provision (Form 42-2E, Line 6)	(24,270)
3	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4	Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2004 to December 2004 (Lines 1 + 2 + 3)	$ (10,820,135)

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Form 42-2E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated 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	$371,639	$371,639	$371,639	$371,639	$371,639	$4,459,665
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	371,639	371,639	371,639	371,639	371,639	4,459,665
4	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5E, Line 9)	7,100	93,932	89,177	400,755	520,349	1,830,170	1,254,431	2,205,460	2,205,459	2,208,345	2,208,345	2,208,345	15,231,868
	b. Capital Investment Projects (Form 42-7E, Line 9)	0	0	0	0	0	0	0	0	0	1,759	5,158	16,745	23,662
	c. Total Jurisdictional ECRC Costs	7,100	93,932	89,177	400,755	520,349	1,830,170	1,254,431	2,205,460	2,205,459	2,210,104	2,213,503	2,225,090	15,255,530
5	Over/(Under) Recovery (Line 3 - Line 4c)	371,005	262,605	212,923	(74,961)	(147,200)	(1,401,173)	(817,643)	(1,833,821)	(1,833,820)	(1,838,465)	(1,841,864)	(1,853,451)	(10,795,865)
6	Interest Provision (Form 42-3E, Line 10)	157	487	709	764	661	(103)	(1,039)	(2,166)	(3,639)	(5,166)	(6,698)	(8,237)	(24,270)
7	Beginning Balance True-Up & Interest Provision	0	371,162	634,254	847,886	773,689	627,150	(774,126)	(1,592,808)	(3,428,795)	(5,266,254)	(7,109,885)	(8,958,447)	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)	(3,467,628)	(5,305,087)	(7,148,718)	(8,997,280)	(10,858,968)	(10,858,968)
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)	($3,467,628)	($5,305,087)	($7,148,718)	($8,997,280)	($10,858,968)	($10,858,968)

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

Form 42-3E

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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
1	Beginning True-Up Amount (Form 42-2E, Line 7 + 7a + 10)	($38,833)	$332,329	$595,421	$809,053	$734,856	$588,317	($812,959)	($1,631,641)	($3,467,628)	($5,305,087)	($7,148,718)	($8,997,280)	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	332,172	594,934	808,344	734,092	587,656	(812,856)	(1,630,602)	(3,465,462)	(5,301,448)	(7,143,552)	(8,990,582)	(10,850,731)	
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)	(5,097,103)	(8,769,076)	(12,448,639)	(16,139,300)	(19,848,011)	
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)	(2,548,552)	(4,384,538)	(6,224,320)	(8,069,650)	(9,924,006)	
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%	1.00%	1.00%	1.00%	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%	1.00%	1.00%	1.00%	1.00%	1.00%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	2.56%	2.52%	2.43%	2.37%	2.40%	2.21%	2.05%	2.05%	2.00%	2.00%	2.00%	2.00%	
8	Average Interest Rate (Line 7 x 1/2)	1.280%	1.260%	1.215%	1.185%	1.200%	1.105%	1.025%	1.025%	1.000%	1.000%	1.000%	1.000%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.107%	0.105%	0.101%	0.099%	0.100%	0.092%	0.085%	0.085%	0.083%	0.083%	0.083%	0.083%	
10	Interest Provision for the Month (Line 4 x Line 9)	$157	$487	$709	$764	$661	($103)	($1,039)	($2,166)	($3,639)	($5,186)	($6,698)	($8,237)	($24,270)

PROGRESS ENERGY FLORIDA

Form 42 4E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

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	473,260	50,000	423,260	847%
1a	Substation Environmental Investigation, Remediation, and Pollution Prevention - Costs	(25,000)	(25,000)	0	0%
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	14,970,455	4,074,000	10,896,455	267%
3a	Pipeline Integrity Management	10,000	0	10,000	100%
4	Above Ground Tank Secondary Containment	0	0	0	0%
2	Total O&M Activities	15,428,715	4,099,000	11,329,715	276%
3	Recoverable Costs Allocated to Energy	0	0	0	0%
4	Recoverable Costs Allocated to Demand	15,428,715	4,099,000	11,329,715	276%

Notes:

Column (1) is the End of Period Totals on Form 42-5E
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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Form 42-5E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
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)	(18,798)	30,107	30,107	30,107	30,107	30,107	473,260
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)	(2,084)	(2,084)	(2,084)	(2,084)	(25,000)
2	Distribution System Environmental Investigation, Remediation, and Pollution	3,566	75,356	45,663	265,885	486,038	1,840,496	1,275,496	2,195,591	2,195,591	2,195,591	2,195,591	2,195,591	14,970,455
3a	Pipeline Integrity Management, Review/Update Plan and Risk Assessments	0	0	0	0	0	0	0	0	0	3,333	3,333	3,334	10,000
4	Above Ground Tank Secondary Containment	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total of O&M Activities	8,489	101,608	106,301	454,643	536,790	1,838,198	1,254,616	2,223,615	2,223,614	2,226,947	2,226,947	2,226,948	15,428,715
3	Recoverable Costs Allocated to Energy - Transm	0	0	0	0	0	0	0	0	0	0	0	0	0
	Recoverable Costs Allocated to Energy - Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0
	Recoverable Costs Allocated to Energy - Production	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)	(20,881)	28,024	28,023	28,023	28,023	28,023	448,260
	Recoverable Costs Allocated to Demand - Distrib	3,566	75,356	45,663	265,885	486,038	1,840,496	1,275,496	2,195,591	2,195,591	2,195,591	2,195,591	2,195,591	14,970,455
	Recoverable Costs Allocated to Demand - Production	0	0	0	0	0	0	0	0	0	3,333	3,333	3,334	10,000
5	Retail Transmission Energy Jurisdictional Factor	0.98400	0.97430	0.97540	0.97570	0.98000	0.97680	0.97770	0.97770	0.97770	0.97770	0.97770	0.97770	
	Retail Distribution Energy Jurisdictional Factor	0.98400	0.97430	0.97540	0.97570	0.98000	0.97680	0.97770	0.97770	0.97770	0.97770	0.97770	0.97770	
	Retail Production Energy Jurisdictional Factor	0.98400	0.97430	0.97540	0.97570	0.98000	0.97680	0.97770	0.97770	0.97770	0.97770	0.97770	0.97770	
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	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	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
	Jurisdictional Energy Recoverable Costs - Distrib (A)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jurisdictional Energy Recoverable Costs - Production (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)	20,210	20,209	20,209	20,209	20,209	323,264
	Jurisdictional Demand Recoverable Costs - Distrib (B)	3,549	75,001	45,448	264,633	483,749	1,831,827	1,269,489	2,185,250	2,185,250	2,185,250	2,185,250	2,185,250	14,899,946
	Jurisdictional Demand Recoverable Costs - Production (B)	0	0	0	0	0	0	0	0	0	2,886	2,886	2,886	8,658
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	$2,205,460	$2,205,459	$2,208,345	$2,208,345	$2,208,345	$15,231,868

Notes:

(A) Line 3 x Line 5

(B) Line 4 x Line 6

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PROGRESS ENERGY FLORIDA

Form 42 6E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

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	18,569	0	18,569	100%
	4a Above Ground Tank Secondary Containment - Turner CT's	5,299	0	5,299	100%
	4b Above Ground Tank Secondary Containment - Bartow CT's	949	0	949	100%
	4c Above Ground Tank Secondary Containment - Crystal River 1 & 2	3,051	0	3,051	100%
2	Total Capital Investment Activities	27,868	0	27,868	100%
3	Recoverable Costs Allocated to Energy	0	0	0	0%
4	Recoverable Costs Allocated to Demand	27,868	0	27,868	100%

Notes:

Column (1) is the End of Period Totals on Form 42-7E
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

PROGRESS ENERGY FLORIDA

Form 42-7E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to 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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
1	Description of Investment Projects (A)													
	3b Pipeline Integrity Management - Bartow/Anclote Pipeline	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,514	$4,658	$12,397	$18,569
	4a Above Ground Tank Secondary Containment - Turner CTs	0	0	0	0	0	0	0	0	0	0	0	5,299	5,299
	4b Above Ground Tank Secondary Containment - Bartow CTs	0	0	0	0	0	0	0	0	0	0	0	949	949
	4c Above Ground Tank Secondary Containment - Crystal River 1&2	0	0	0	0	0	0	0	0	0	467	1,173	1,411	3,051
2	Total Investment Projects - Recoverable Costs	0	0	0	0	0	0	0	0	0	1,981	5,831	20,056	27,868
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	467	1,173	1,411	3,051
	Recoverable Costs Allocated to Demand - Production - Intermediate	0	0	0	0	0	0	0	0	0	1,514	4,658	12,397	18,569
	Recoverable Costs Allocated to Demand - Production - Peaking	0	0	0	0	0	0	0	0	0	0	0	6,248	6,248
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	0.0000000	0.0000000	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	448	1,126	1,354	2,928
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	0	0	0	0	0	0	0	0	0	1,311	4,033	10,733	16,076
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	0	0	0	0	0	0	0	0	0	0	0	4,659	4,659
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,759	$5,158	$16,745	$23,662

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
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$338,152	
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	651,842	
	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	989,994	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	(2,970)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	313,690	651,842	0	
5	Net Investment (Lines 2 - 3 + 4)	$0	0	0	0	0	0	0	0	0	0	313,690	651,842	987,024	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	156,845	482,766	819,433	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (D)		0	0	0	0	0	0	0	0	0	1,089	3,351	5,688	$10,128
	b. Debt Component (Line 6 x 3.25% x 1/12)		0	0	0	0	0	0	0	0	0	425	1,307	2,219	3,951
8	Investment Expenses														
	a. Depreciation (Line 2 x 3.04% x 1/12) (E)		0	0	0	0	0	0	0	0	0	0	0	2,970	2,970
	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	1,520	1,520
	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	1,514	4,658	12,397	18,569
	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	1,514	4,658	12,397	18,569
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	0.0000000	0.0000000	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	0	0	1,311	4,033	10,733	16,076
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,311	$4,033	$10,733	$16,076

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 @ $0 and end of period @ $989,994 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) Lines 6 x 8.3300% x 1/12. Gross-up for taxes based on ROE of 12.00%, equity component of capital structure of 5.12%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 1992 Rate Case (Order No. PSC-92-1197-FOF-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 for Bartow/Anclote Pipeline project. 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)

Exhibit ____ (JP-1)
Revised 9/05/03
Progress Energy Florida
Docket No. 030007-EI
Page 9 of 12

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to 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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$502,700	
	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	502,700	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	(2,011)	
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	500,689	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	250,345	
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	1,738	$1,738
	b. Debt Component (Line 6 x 3.25% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	678	678
8	Investment Expenses														
	a. Depreciation (Line 2 x 4.45% x 1/12) (E)		0	0	0	0	0	0	0	0	0	0	0	2,011	2,011
	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	873	873
	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	5,299	5,299
	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	5,299	5,299
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	3,951	3,951
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,951	$3,951

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 @ $0 and end of period @ $502,700 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) Lines 6 x 8.3300% x 1/12. Gross-up for taxes based on ROE of 12.00%, equity component of capital structure of 6.12%, and statutory income tax rate of 38.575% (expansion factor of 1.629002). Based on 1992 Rate Case (Order No. PSC-92-1197-FOF-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 for Above Ground Tank Secondary Containment - Turner CTs project. 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
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to 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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$91,900	
	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	91,900	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	(368)	
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	91,532	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	45,766	
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	318	$318
	b. Debt Component (Line 6 x 3.25% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	124	124
8	Investment Expenses														
	a. Depreciation (Line 2 x 4.45% x 1/12) (E)		0	0	0	0	0	0	0	0	0	0	0	368	368
	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	140	140
	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	949	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		0	0	0	0	0	0	0	0	0	0	0	949	949
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	708	708
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$708	$708

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 @ $0 and end of period @ $91,900 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) Lines 6 x 8.3300% x 1/12. Gross-up for taxes based on ROE of 12.00%, equity component of capital structure of 5.12%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 1992 Rate Case (Order No. PSC-92-1197-FOF-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 - Bartow CTs.
(G) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Bartow CTs project. 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
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to 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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,000	$50,000	$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)	$0	0	0	0	0	0	0	0	0	0	50,000	100,000	100,000	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	(150)	(450)	(750)	
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	49,850	99,550	99,250	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	24,925	74,700	99,400	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (D)		0	0	0	0	0	0	0	0	0	173	519	690	$1,382
	b. Debt Component (Line 6 x 3.25% x 1/12)		0	0	0	0	0	0	0	0	0	68	202	269	539
8	Investment Expenses														
	a. Depreciation (Line 2 x 3.04% x 1/12) (E)		0	0	0	0	0	0	0	0	0	150	300	300	750
	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	76	152	152	380
	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	467	1,173	1,411	3,051
	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	467	1,173	1,411	3,051
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	0.9695700	0.9695700	0.9695700	
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	448	1,126	1,354	2,928
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$448	$1,126	$1,354	$2,928

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 @ $0 and end of period @ $100,000 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) Lines 6 x 8.3300% x 1/12. Gross-up for taxes based on ROE of 12.00%, equity component of capital structure of 5.12%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 1992 Rate Case (Order No. PSC-92-1197-FOF-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 Above Ground Tank Secondary Containment - Crystal River 1&2.
(G) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Crystal River 1&2 project. 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 Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

Hopping Green & Sams

Attorneys and Counselors

October 2, 2003

BY HAND-DELIVERY

Blanca Bayó
Director, Division of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399

Re: Docket No. 030007-EI

Dear Ms. Bayó:

On behalf of Progress Energy Florida, Inc., I enclose for filing the original and fifteen (15) copies of a table to be substituted for the table presented in the next to last page of Exhibit 1 (JP-1) originally filed with of the Direct Testimony of Javier Portuondo on April 1, 2003.

The substitute table includes adjustments based on disclosures in the Staff Audit Report dated July 15, 2003. The adjustments included in the substitute table were accounted for in the Estimated/Actual True-up amount for 2003 presented in the revised Direct Testimony Mr. Portuondo filed on September 5, 2003. Accordingly, such adjustments do not affect the total true-up amount or proposed ECRC factors presented in the Direct Testimony of Mr. Portuondo filed on September 8, 2003.

By copy of this letter, the enclosed substitute table has been furnished to the parties on the attached service list. Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning it to me. If you have any questions regarding this filing, please give me a call at 425-2359.

Very truly yours,

HOPPING GREEN & SAMS, P.A.

Gary V. Perko

GVP/jlm
cc: Certificate of Service

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030007-EI EXHIBIT NO. 4
COMPANY/ WITNESS: JP-1 -exchange
DATE: 11-12-03

DOCUMENT NUMBER-DATE
09560 OCT-2 8
FPSC-COMMISSION CLERK

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by regular U.S. mail and/or hand-delivery (*) to the following in Docket No. 030007-EI this 2nd day of October, 2003.

Marlene Stern*
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

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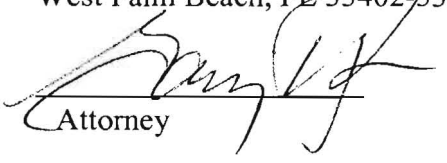
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West Palm Beach, FL 33402-3395



Attorney

Progress Energy - Florida
ECRC - 2002

UPDATED: 10/01/2003

Month posted	Vendor	Invoice Date	Invoice #	Work Done	Amount	T or D	Purpose
Dec	SWS	11/26/2002	24365	11/4/2002	18,512.86	T	Emergency response to petrolem spill at Curlew Substation
	SWS	12/13/2002	24521	12/4/2002	441.00	T	Emergency response to petrolem spill at Curlew Substation
Dec - Accr	Pike	1/3/2003	457610	12/29/2002	3,005.00	D	Oily dirt removal from transformers in the Apopka area
Dec - Accr	Pike	1/3/2003	458737		3,005.00	D	**Accrual estimate per Daryl O'Cain - Actual invoice came in at $3,473.28**
	Viasys	12/14/2002	105065-C	12/12/2002	1,254.00	D	Oily dirt removal from transformers in the Jamestown area
	Viasys	12/21/2002	105076-C	12/16/2002	864.00	D	Oily dirt removal from transformers in the Jamestown area
	Viasys	12/21/2002	105077-C	12/17/2002	2,996.00	D	Oily dirt removal from transformers in the Jamestown area
Dec-Accr	Viasys				2,877.00	D	**Accrual estimate per Daryl O'Cain - A/P has not authorized payment**
	SWS	11/14/2002	24239	11/9/2002	1,679.00	D	Emergency response to non-pcb transformer oil spill - Winter Pk
	US Filter	12/2/2002	9903737	11/25/2002	7,865.40	D	Disposal of oily dirt related to TRIP program
	US Filter	11/15/2002	71052721	10/8/2002	1,100.00	D	Analysis of oily dirt related to TRIP program - various spill sites
Dec	Kent				2,106.04	D	See attached documentation provided by Kent Hedrick
	Kent				498.00	T	See attached documentation provided by Kent Hedrick
	Other labor			12/4/2002	6,559.59	T	Overtime to clean up Curlew Substation
	Viasys	10/19/2002	607175	10/16/2002	1,848.00	D	Oily dirt removal from transformers in the Tarpon Springs area
	Viasys	10/19/2002	507781	10/17/2002	1,868.00	D	Oily dirt removal from transformers in the Clearwater area
	Viasys	10/26/2002	607176	10/19/2002	1,536.00	D	Oily dirt removal from transformers in the 7 Springs area
	Viasys	10/19/2002	507810	10/21/2002	2,867.00	D	Oily dirt removal from transformers in the St. Petersburg area
	Viasys	10/19/2002	507810	10/22/2002	3,243.75	D	Oily dirt removal from transformers in the St. Petersburg area
	55 Gl Blk/W				170.59	D	Transformer oil leak repair
					$ 64,296.23		**Total 2002**

2002 FPSC Audit Adjustments

July 2003	Remove Regular Labor Charges	**(5,957.00)**	Reversed per Audit Finding - Disclosure No. 1
July 2003	Remove Emergency Response Clean Up	**(18,512.86)**	Reversed per Audit Finding - Disclosure No. 2
July 2003	Remove Emergency Response Clean Up	**(441.00)**	Reversed per Audit Finding - Disclosure No. 2
July 2003	Remove Emergency Response Clean Up	**(1,679.00)**	Reversed per Audit Finding - Disclosure No. 2
		$ 37,706.37	**Total Revised**

Docket No. 030007
Progress Energy Florida
Exhibit ____ (JP-1)
Substitute Table
Page 1 of 1

Form Appendix
Revised 10/17/03

EXHIBIT __ (JP-2)

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

JANUARY 2003 - DECEMBER 2003
Calculation of the Current Period Estimated/Actual Amount
Actuals for Period January through July 2003
Estimated for Period August through December 2003

PROGRESS ENERGY FLORIDA

Form 42-1E
Revised 10/17/03

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 through December 2003
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$ (10,798,672)
2	Interest Provision (Form 42-2E, Line 6)	(24,272)
3	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4	Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2004 to December 2004 (Lines 1 + 2 + 3)	$ (10,822,944)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

Form 42-2E
Revised 10/17/03

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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated 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	$371,639	$371,639	$371,639	$371,639	$371,639	$4,459,665
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	371,639	371,639	371,639	371,639	371,639	4,459,665
4	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5E, Line 9)	7,100	93,932	89,177	400,755	520,349	1,830,170	1,254,431	2,205,460	2,205,459	2,208,345	2,208,345	2,208,345	15,231,868
	b. Capital Investment Projects (Form 42-7E, Line 9)	0	0	0	0	0	0	0	0	0	2,057	6,003	18,409	26,469
	c. Total Jurisdictional ECRC Costs	7,100	93,932	89,177	400,755	520,349	1,830,170	1,254,431	2,205,460	2,205,459	2,210,402	2,214,348	2,226,754	15,258,337
5	Over/(Under) Recovery (Line 3 - Line 4c)	371,005	262,605	212,923	(74,961)	(147,200)	(1,401,173)	(817,643)	(1,833,821)	(1,833,820)	(1,838,763)	(1,842,709)	(1,855,115)	(10,798,672)
6	Interest Provision (Form 42-3E, Line 10)	157	487	709	764	661	(103)	(1,039)	(2,166)	(3,639)	(5,166)	(6,698)	(8,239)	(24,272)
7	Beginning Balance True-Up & Interest Provision	0	371,162	634,254	847,886	773,689	627,150	(774,126)	(1,592,808)	(3,428,795)	(5,266,254)	(7,110,183)	(8,959,590)	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)	(3,467,628)	(5,305,087)	(7,149,016)	(8,998,423)	(10,861,777)	(10,861,777)
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)	($3,467,628)	($5,305,087)	($7,149,016)	($8,998,423)	($10,861,777)	($10,861,777)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

Form 42-3E
Revised 10/17/03

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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
1	Beginning True-Up Amount (Form 42-2E, Line 7 + 7a + 10)	($38,833)	$332,329	$595,421	$809,053	$734,856	$588,317	($812,959)	($1,631,641)	($3,467,628)	($5,305,087)	($7,149,016)	($8,998,423)	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	332,172	594,934	808,344	734,092	587,656	(812,856)	(1,630,602)	(3,465,462)	(5,301,448)	(7,143,850)	(8,991,725)	(10,853,538)	
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)	(5,097,103)	(8,769,076)	(12,448,937)	(16,140,741)	(19,851,961)	
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)	(2,548,552)	(4,384,538)	(6,224,469)	(8,070,371)	(9,925,981)	
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%	1.00%	1.00%	1.00%	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%	1.00%	1.00%	1.00%	1.00%	1.00%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	2.56%	2.52%	2.43%	2.37%	2.40%	2.21%	2.05%	2.05%	2.00%	2.00%	2.00%	2.00%	
8	Average Interest Rate (Line 7 x 1/2)	1.280%	1.260%	1.215%	1.185%	1.200%	1.105%	1.025%	1.025%	1.000%	1.000%	1.000%	1.000%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.107%	0.105%	0.101%	0.099%	0.100%	0.092%	0.085%	0.085%	0.083%	0.083%	0.083%	0.083%	
10	Interest Provision for the Month (Line 4 x Line 9)	$157	$487	$709	$764	$661	($103)	($1,039)	($2,166)	($3,639)	($5,166)	($6,698)	($8,239)	($24,272)

PROGRESS ENERGY FLORIDA

Form 42 4E
Revised 10/17/03

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

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	473,260	50,000	423,260	847%
1a	Substation Environmental Investigation, Remediation, and Pollution Prevention - Costs	(25,000)	(25,000)	0	0%
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	14,970,455	4,074,000	10,896,455	267%
3a	Pipeline Integrity Management	10,000	0	10,000	100%
4	Above Ground Tank Secondary Containment	0	0	0	0%
2	Total O&M Activities	15,428,715	4,099,000	11,329,715	276%
3	Recoverable Costs Allocated to Energy	0	0	0	0%
4	Recoverable Costs Allocated to Demand	15,428,715	4,099,000	11,329,715	276%

Notes:

Column (1) is the End of Period Totals on Form 42-5E
Column (2) = Estimated actual
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 2003 to December 2003

Form 42-5E
Revised 10/17/03

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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
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)	(18,798)	30,107	30,107	30,107	30,107	30,107	473,260
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)	(2,084)	(2,084)	(2,084)	(2,084)	(25,000)
2	Distribution System Environmental Investigation, Remediation, and Pollution	3,566	75,356	45,663	265,885	486,038	1,840,496	1,275,496	2,195,591	2,195,591	2,195,591	2,195,591	2,195,591	14,970,455
3a	Pipeline Integrity Management, Review/Update Plan and Risk Assessments	0	0	0	0	0	0	0	0	0	3,333	3,333	3,334	10,000
4	Above Ground Tank Secondary Containment	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total of O&M Activities	8,489	101,608	106,301	454,643	536,790	1,838,198	1,254,616	2,223,615	2,223,614	2,226,947	2,226,947	2,226,948	15,428,715
3	Recoverable Costs Allocated to Energy - Transm	0	0	0	0	0	0	0	0	0	0	0	0	0
	Recoverable Costs Allocated to Energy - Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0
	Recoverable Costs Allocated to Energy - Production	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)	(20,881)	28,024	28,023	28,023	28,023	28,023	448,260
	Recoverable Costs Allocated to Demand - Distrib	3,566	75,356	45,663	265,885	486,038	1,840,496	1,275,496	2,195,591	2,195,591	2,195,591	2,195,591	2,195,591	14,970,455
	Recoverable Costs Allocated to Demand - Production	0	0	0	0	0	0	0	0	0	3,333	3,333	3,334	10,000
5	Retail Transmission Energy Jurisdictional Factor	0.98400	0.97430	0.97540	0.97570	0.98000	0.97680	0.97770	0.97770	0.97770	0.97770	0.97770	0.97770	
	Retail Distribution Energy Jurisdictional Factor	0.98400	0.97430	0.97540	0.97570	0.98000	0.97680	0.97770	0.97770	0.97770	0.97770	0.97770	0.97770	
	Retail Production Energy Jurisdictional Factor	0.98400	0.97430	0.97540	0.97570	0.98000	0.97680	0.97770	0.97770	0.97770	0.97770	0.97770	0.97770	
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	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	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
	Jurisdictional Energy Recoverable Costs - Distrib (A)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Jurisdictional Energy Recoverable Costs - Production (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)	20,210	20,209	20,209	20,209	20,209	323,264
	Jurisdictional Demand Recoverable Costs - Distrib (B)	3,549	75,001	45,448	264,633	483,749	1,831,827	1,269,489	2,185,250	2,185,250	2,185,250	2,185,250	2,185,250	14,899,946
	Jurisdictional Demand Recoverable Costs - Production (B)	0	0	0	0	0	0	0	0	0	2,886	2,886	2,886	8,658
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	$2,205,460	$2,205,459	$2,208,345	$2,208,345	$2,208,345	$15,231,868

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

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PROGRESS ENERGY FLORIDA

Form 42 6E
Revised 10/17/03

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

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	20,686	0	20,686	100%
	4a Above Ground Tank Secondary Containment - Turner CT's	5,662	0	5,662	100%
	4b Above Ground Tank Secondary Containment - Bartow CT's	1,074	0	1,074	100%
	4c Above Ground Tank Secondary Containment - Crystal River 1 & 2	3,687	0	3,687	100%
2	Total Capital Investment Activities	31,109	0	31,109	100%
3	Recoverable Costs Allocated to Energy	0	0	0	0%
4	Recoverable Costs Allocated to Demand	31,109	0	31,109	100%

Notes:

Column (1) is the End of Period Totals on Form 42-7E
Column (2) = Estimated actual
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 2003 to December 2003

Form 42-7E
Revised 10/17/03

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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
1	Description of Investment Projects (A)													
	3b Pipeline Integrity Management - Bartow/Anclote Pipeline	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,741	$5,359	$13,586	$20,686
	4a Above Ground Tank Secondary Containment - Turner CTs	0	0	0	0	0	0	0	0	0	0	0	5,662	5,662
	4b Above Ground Tank Secondary Containment - Bartow CTs	0	0	0	0	0	0	0	0	0	0	0	1,074	1,074
	4c Above Ground Tank Secondary Containment - Crystal River 1&2	0	0	0	0	0	0	0	0	0	573	1,421	1,693	3,687
2	Total Investment Projects - Recoverable Costs	0	0	0	0	0	0	0	0	0	2,314	6,780	22,015	31,109
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	573	1,421	1,693	3,687
	Recoverable Costs Allocated to Demand - Production - Intermediate	0	0	0	0	0	0	0	0	0	1,741	5,359	13,586	20,686
	Recoverable Costs Allocated to Demand - Production - Peaking	0	0	0	0	0	0	0	0	0	0	0	6,736	6,736
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	0.0000000	0.0000000	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	550	1,364	1,625	3,538
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	0	0	0	0	0	0	0	0	0	1,507	4,640	11,762	17,909
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	0	0	0	0	0	0	0	0	0	0	0	5,022	5,022
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,057	$6,003	$18,409	$26,469

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
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$338,152	
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	651,842	
	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	989,994	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	(2,970)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	313,690	651,842	0	
5	Net Investment (Lines 2 - 3 + 4)	$0	0	0	0	0	0	0	0	0	0	313,690	651,842	987,024	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	156,845	482,766	819,433	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (D)		0	0	0	0	0	0	0	0	0	1,405	4,325	7,341	$13,071
	b. Debt Component (Line 6 x 2.57% x 1/12)		0	0	0	0	0	0	0	0	0	336	1,034	1,755	3,125
8	Investment Expenses														
	a. Depreciation (Line 2 x 3.60% x 1/12) (E)		0	0	0	0	0	0	0	0	0	0	0	2,970	2,970
	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	1,520	1,520
	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	1,741	5,359	13,586	20,686
	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	1,741	5,359	13,586	20,686
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	0.0000000	0.0000000	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	0	0	1,507	4,640	11,762	17,909
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,507	$4,640	$11,762	$17,909

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 @ $0 and end of period @ $989,994 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) Amortization period is approximately 28 years for Bartow/Anclote Pipeline.
(G) Description and reason for 'Other' adjustments to investment expenses for Bartow/Anclote Pipeline project. 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)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

Form 42-8E
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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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$502,700	
	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	502,700	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	(2,011)	
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	500,689	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	250,345	
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	2,243	$2,243
	b. Debt Component (Line 6 x 2.57% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	536	536
8	Investment Expenses														
	a. Depreciation (Line 2 x 4.80% x 1/12) (E)		0	0	0	0	0	0	0	0	0	0	0	2,011	2,011
	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	873	873
	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	5,662	5,662
	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	5,662	5,662
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	4,222	4,222
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,222	$4,222

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 @ $0 and end of period @ $502,700 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) Amortization period is approximately 21 years for Above Ground Tank Secondary Containment - Turner CTs.
(G) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Turner CTs project. 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)

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

Form 42-8E
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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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$91,100	
	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	91,100	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	(433)	
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	90,667	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	45,334	
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	406	$406
	b. Debt Component (Line 6 x 2.57% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	97	97
8	Investment Expenses														
	a. Depreciation (Line 2 x 5.70% x 1/12) (E)		0	0	0	0	0	0	0	0	0	0	0	433	433
	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	139	139
	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	1,074	1,074
	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	1,074	1,074
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	801	801
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$801	$801

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 @ $0 and end of period @ $91,900 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) Amortization period is approximately 21 years for Above Ground Tank Secondary Containment - Bartow CTs.
(G) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Bartow CTs project. 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
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2003 to December 2003

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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	Estimated August 03	Estimated September 03	Estimated October 03	Estimated November 03	Estimated December 03	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,000	$50,000	$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)	$0	0	0	0	0	0	0	0	0	0	50,000	100,000	100,000	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	(221)	(663)	(1,104)	
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	49,779	99,338	98,896	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	24,890	74,558	99,117	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (D)		0	0	0	0	0	0	0	0	0	223	668	888	$1,779
	b. Debt Component (Line 6 x 2.57% x 1/12)		0	0	0	0	0	0	0	0	0	53	160	212	425
8	Investment Expenses														
	a. Depreciation (Line 2 x 5.30% x 1/12) (E)		0	0	0	0	0	0	0	0	0	221	442	442	1,104
	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	76	152	151	379
	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	573	1,421	1,693	3,687
	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	573	1,421	1,693	3,687
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	550	1,364	1,625	3,538
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$550	$1,364	$1,625	$3,538

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 @ $0 and end of period @ $100,000 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 5.3% 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 for Above Ground Tank Secondary Containment - Crystal River 1&2 project. 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)

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Form Appendix

EXHIBIT __ (JP-2)

ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1P THROUGH 42-7P

JANUARY 2004 - DECEMBER 2004
Calculation of the Projected Period Amount

PROGRESS ENERGY FLORIDA

Form 42-1P

Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2004 to December 2004

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, Page 2 of 2, Lines 7 through 9)	$4,270,969	$525,973	$5,144,010	$225,028	$10,165,980
	b Projected Capital Projects (Form 42-3P, Page 2 of 2, Line 7 through 9)	(220,723)	0	0	282,462	61,739
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	4,050,247	525,973	5,144,010	507,489	10,227,719
2	True-up for Estimated Over/(Under) Recovery for the current period January 2003 through December 2003 (Form 42-2E, Line 5 + 6 + 10)	0	(229,288)	(10,568,373)	(22,474)	($10,820,135)
3	Final True-up for the period January 2002 to December 2002 (Form 42-1A, Line 3)	0	(729)	(38,104)	0	($38,833)
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection period January 2004 to December 2004 (Line 1 - Line 2 - Line 3)	4,050,247	755,990	15,750,488	529,963	21,086,687
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of .00072)	4,053,163	756,534	15,761,828	530,345	$21,101,869

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Form 42-2P

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 to December 2004

O&M Activities
(In Dollars)

Line		Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
1	Description of O&M Activities													
	1 Substation Environmental Investigation, Remediation, and Pollution Prevention	62,863	62,863	62,863	62,863	62,863	62,863	62,863	62,863	62,863	62,863	62,863	62,863	754,353
	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)
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	5,168,353
	3a Pipeline Integrity Management, Review/Update Plan and Risk Assessments	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	245,000
	4 Above Ground Tank Secondary Containment	0	0	0	0	0	0	0	0	0	0	0	0	0
	5 SO_2 Emissions Allowances	355,991	319,736	325,769	293,886	384,405	414,723	435,091	444,867	413,735	359,295	320,017	332,485	4,400,000
2	Total of O&M Activities	867,883	831,628	837,661	805,778	896,297	926,615	946,983	956,759	925,627	871,187	831,909	844,377	10,542,706
3	Recoverable Costs Allocated to Energy	355,991	319,736	325,769	293,886	384,405	414,723	435,091	444,867	413,735	359,295	320,017	332,485	4,400,004
4	Recoverable Costs Allocated to Demand - Transm	60,779	60,779	60,779	60,779	60,779	60,779	60,779	60,779	60,779	60,779	60,779	60,779	729,353
	Recoverable Costs Allocated to Demand - Distrib	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	5,168,353
	Recoverable Costs Allocated to Demand - Production	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	245,000
5	Retail Energy Jurisdictional Factor	0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600	
6	Retail Transmission Demand Jurisdictional Factor	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	
	Retail Distribution Demand Jurisdictional Factor	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	
	Retail Production Demand Jurisdictional Factor	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	
7	Jurisdictional Energy Recoverable Costs (A)	344,792	309,456	316,055	285,554	373,457	403,148	423,387	432,495	401,728	348,354	309,712	322,830	4,270,969
8	Jurisdictional Demand Recoverable Costs - Transm (B)	43,831	43,831	43,831	43,831	43,831	43,831	43,831	43,831	43,831	43,831	43,831	43,831	525,973
	Jurisdictional Demand Recoverable Costs - Distrib (B)	428,668	428,668	428,668	428,668	428,668	428,668	428,668	428,668	428,668	428,668	428,668	428,668	5,144,010
	Jurisdictional Demand Recoverable Costs - Production (B)	18,752	18,752	18,752	18,752	18,752	18,752	18,752	18,752	18,752	18,752	18,752	18,752	225,028
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$836,042	$800,707	$807,305	$776,805	$864,708	$894,399	$914,638	$923,746	$892,979	$839,605	$800,963	$814,081	$10,165,980

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

PROGRESS ENERGY FLORIDA

Form 42-3P

Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 to December 2004

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	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	14,972	14,941	14,908	14,878	14,846	14,814	14,782	14,751	14,718	14,687	14,655	14,624	177,576	$177,576	$0
4a Above Ground Tank Secondary Containment - Turner CTs	8,283	8,259	8,235	8,211	8,188	8,163	8,139	8,115	8,092	8,067	8,043	8,020	97,815	97,815	0
4b Above Ground Tank Secondary Containment - Bartow CTs	1,482	1,477	1,473	1,468	1,464	1,459	1,456	1,451	1,447	1,443	1,439	1,434	17,493	17,493	0
4c Above Ground Tank Secondary Containment - Crystal River 1&2	1,507	1,503	1,499	1,497	1,493	1,491	1,486	1,484	1,481	1,478	1,474	1,472	17,865	17,865	0
5 SO_2 Emissions Allowances	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(227,424)	0	(227,424)
2 Total Investment Projects - Recoverable Costs	7,292	7,228	7,163	7,102	7,039	6,975	6,911	6,849	6,786	6,723	6,659	6,598	83,325	$310,749	($227,424)
3 Recoverable Costs Allocated to Energy	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(227,424)		
4 Recoverable Costs Allocated to Demand	26,244	26,180	26,115	26,054	25,991	25,927	25,863	25,801	25,738	25,675	25,611	25,550	310,749		
5 Retail Energy Jurisdictional Factor	0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600			
6 Retail Demand Jurisdictional Factor	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700			
7 Jurisdictional Energy Recoverable Costs (B)	(18,356)	(18,343)	(18,387)	(18,415)	(18,412)	(18,423)	(18,442)	(18,425)	(18,402)	(18,375)	(18,342)	(18,402)	(220,723)		
8 Jurisdictional Demand Recoverable Costs - Production - Base (C)	23,855	23,797	23,738	23,682	23,625	23,567	23,509	23,452	23,395	23,338	23,280	23,224	282,462		
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$5,499	$5,454	$5,351	$5,268	$5,213	$5,144	$5,066	$5,027	$4,993	$4,963	$4,938	$4,823	$61,739		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 14
(B) Line 3 x Line 5
(C) Line 4 x Line 6

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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
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. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	$989,994	989,994	989,994	989,994	989,994	989,994	989,994	989,994	989,994	989,994	989,994	989,994	989,994	
3	Less: Accumulated Depreciation (C)	(2,508)	(5,016)	(7,524)	(10,032)	(12,540)	(15,048)	(17,556)	(20,064)	(22,572)	(25,080)	(27,588)	(30,096)	(32,604)	
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)	$987,486	984,978	982,470	979,962	977,454	974,946	972,438	969,930	967,422	964,914	962,406	959,898	957,390	
6	Average Net Investment		986,232	983,724	981,216	978,708	976,200	973,692	971,184	968,676	966,168	963,660	961,152	958,644	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (D)		8,835	8,813	8,790	8,768	8,745	8,723	8,700	8,678	8,655	8,633	8,610	8,588	$104,538
	b. Debt Component - 2.57%		2,112	2,107	2,101	2,096	2,091	2,085	2,080	2,075	2,069	2,064	2,058	2,053	24,991
8	Investment Expenses														
	a. Depreciation - 3.04% (E)		2,508	2,508	2,508	2,508	2,508	2,508	2,508	2,508	2,508	2,508	2,508	2,508	30,096
	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)		1,517	1,513	1,509	1,506	1,502	1,498	1,494	1,490	1,486	1,482	1,479	1,475	17,951
	e. Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		14,972	14,941	14,908	14,878	14,846	14,814	14,782	14,751	14,718	14,687	14,655	14,624	177,578
	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		14,972	14,941	14,908	14,878	14,846	14,814	14,782	14,751	14,718	14,687	14,655	14,624	177,578
10	Energy Jurisdictional Factor		0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600	
11	Demand Jurisdictional Factor		0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	
12	Retail Energy-Related Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Costs (I)		13,609	13,581	13,551	13,524	13,495	13,465	13,436	13,408	13,378	13,350	13,321	13,293	161,411
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 13,609	$ 13,581	$ 13,551	$ 13,524	$ 13,495	$ 13,465	$ 13,436	$ 13,408	$ 13,378	$ 13,350	$ 13,321	$ 13,293	$ 161,411

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 @ $0 and end of period @ $989,994 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) Lines 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 for Bartow/Anclote Pipeline project. 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 Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

Docket No. 030007-EI
Progress Energy Florida
Exhibit ____ (JP-2)
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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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
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. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	$502,700	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)	(1,864)	(3,728)	(5,592)	(7,457)	(9,321)	(11,185)	(13,049)	(14,913)	(16,777)	(18,642)	(20,506)	(22,370)	(24,234)	
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)	$500,836	498,972	497,108	495,243	493,379	491,515	489,651	487,787	485,923	484,058	482,194	480,330	478,466	
6	Average Net Investment		499,904	498,040	496,176	494,311	492,447	490,583	488,719	486,855	484,990	483,126	481,262	479,398	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (D)		4,478	4,462	4,445	4,428	4,412	4,395	4,378	4,361	4,345	4,328	4,311	4,295	$52,638
	b. Debt Component - 2.57%		1,071	1,067	1,063	1,059	1,055	1,051	1,047	1,043	1,039	1,035	1,031	1,027	12,588
8	Investment Expenses														
	a. Depreciation - 4.45% (E)		1,864	1,864	1,864	1,864	1,864	1,864	1,864	1,864	1,864	1,864	1,864	1,864	22,370
	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)		870	866	863	860	857	853	850	847	844	840	837	834	10,220
	e. Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		8,283	8,259	8,235	8,211	8,188	8,163	8,139	8,115	8,092	8,067	8,043	8,020	97,816
	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		8,283	8,259	8,235	8,211	8,188	8,163	8,139	8,115	8,092	8,067	8,043	8,020	97,815
10	*Energy Jurisdictional Factor*		0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600	
11	Demand Jurisdictional Factor		0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	
12	Retail Energy-Related Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Costs (I)		7,529	7,507	7,485	7,464	7,443	7,420	7,398	7,376	7,355	7,333	7,311	7,290	88,911
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 7,529	$ 7,507	$ 7,485	$ 7,464	$ 7,443	$ 7,420	$ 7,398	$ 7,376	$ 7,355	$ 7,333	$ 7,311	$ 7,290	$ 88,911

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 @ $0 and end of period @ $502,700 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) Lines 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 for Above Ground Tank Secondary Containment - Turner CTs project. 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 Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

Docket No. 030007-EI
Progress Energy Florida
Exhibit ____ (JP-2)
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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 - BARTOW CTs (Project 4b)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
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. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	$91,100	91,100	91,100	91,100	91,100	91,100	91,100	91,100	91,100	91,100	91,100	91,100	91,100	
3	Less: Accumulated Depreciation (C)	(341)	(679)	(1,017)	(1,354)	(1,692)	(2,030)	(2,368)	(2,706)	(3,044)	(3,381)	(3,719)	(4,057)	(4,395)	
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)	$90,759	90,421	90,083	89,746	89,408	89,070	88,732	88,394	88,056	87,719	87,381	87,043	86,705	
6	Average Net Investment		90,590	90,252	89,914	89,577	89,239	88,901	88,563	88,225	87,887	87,550	87,212	86,874	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (D)		812	809	805	802	799	796	793	790	787	784	781	778	$9,536
	b. Debt Component - 2.57%		194	193	193	192	191	190	190	189	188	188	187	186	2,281
8	Investment Expenses														
	a. Depreciation - 4.45% (E)		338	338	338	338	338	338	338	338	338	338	338	338	4,054
	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)		138	138	137	137	136	136	135	135	134	134	133	133	1,624
	e. Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,482	1,477	1,473	1,468	1,464	1,459	1,456	1,451	1,447	1,443	1,439	1,434	17,495
	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		1,482	1,477	1,473	1,468	1,464	1,459	1,456	1,451	1,447	1,443	1,439	1,434	17,493
10	Energy Jurisdictional Factor		0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600	
11	Demand Jurisdictional Factor		0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	
12	Retail Energy-Related Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Costs (I)		1,347	1,343	1,339	1,334	1,331	1,326	1,323	1,319	1,315	1,312	1,308	1,303	15,901
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 1,347	$ 1,343	$ 1,339	$ 1,334	$ 1,331	$ 1,326	$ 1,323	$ 1,319	$ 1,315	$ 1,312	$ 1,308	$ 1,303	$ 15,901

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 @ $0 and end of period @ $91,900 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) Lines 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-02-0855-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 - Bartow CTs.
(G) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Bartow CTs project. 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 Millage Rate.

Source:
Line 8c Based on 2002 Rate Case Settlement (Order No. PSC-02-0655-AS-EI)

Docket No. 030007-EI
Progress Energy Florida
Exhibit ____ (JP-2)
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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 - CRYSTAL RIVER 1 & 2 (Project 4c)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
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. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	$100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	
3	Less: Accumulated Depreciation (C)	(633)	(886)	(1,140)	(1,393)	(1,646)	(1,900)	(2,153)	(2,406)	(2,660)	(2,913)	(3,166)	(3,420)	(3,673)	
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)	$99,367	99,114	98,860	98,607	98,354	98,100	97,847	97,594	97,340	97,087	96,834	96,580	96,327	
6	Average Net Investment		99,240	98,987	98,734	98,480	98,227	97,974	97,720	97,467	97,214	96,960	96,707	96,454	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (D)		889	887	884	882	880	878	875	873	871	869	866	864	$10,518
	b. Debt Component - 2.57%		213	212	211	211	210	210	209	209	208	208	207	207	2,515
8	Investment Expenses														
	a. Depreciation - 3.04% (E)		253	253	253	253	253	253	253	253	253	253	253	253	3,040
	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)		151	151	151	150	150	150	149	149	148	148	148	147	1,792
	e. Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,507	1,503	1,499	1,497	1,493	1,491	1,486	1,484	1,481	1,478	1,474	1,472	17,865
	a. Recoverable Costs Allocated to Energy		-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand		1,507	1,503	1,499	1,497	1,493	1,491	1,486	1,484	1,481	1,478	1,474	1,472	17,865
10	Energy Jurisdictional Factor		0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600	
11	Demand Jurisdictional Factor		0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	
12	Retail Energy-Related Costs (H)		-	-	-	-	-	-	-	-	-	-	-	-	-
13	Retail Demand-Related Costs (I)		1,370	1,366	1,363	1,361	1,357	1,355	1,351	1,349	1,346	1,343	1,340	1,338	16,239
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 1,370	$ 1,366	$ 1,363	$ 1,361	$ 1,357	$ 1,355	$ 1,351	$ 1,349	$ 1,346	$ 1,343	$ 1,340	$ 1,338	$ 16,239

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 @ $0 and end of period @ $100,000 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) Lines 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 Above Ground Tank Secondary Containment - Crystal River 1&2.
(G) Description and reason for 'Other' adjustments to investment expenses for Above Ground Tank Secondary Containment - Crystal River 1&2 project. 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
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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
1	Working Capital Dr (Cr)														
	a. 1581001 SO_2 Emission Allowance Inventory	$ -	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	b. 25401FL Auctioned SO_2 Allowance	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	
2	Total Working Capital	$ (1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	
3	Average Net Investment		(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	
4	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	($183,540)
	b. Debt Component - 2.57%		(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(43,884)
5	Total Return Component (D)		(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(227,424)
6	Expense Dr (Cr)														
	a. 5090001 SO_2 allowance expense		355,991	319,736	325,769	293,886	384,405	414,723	435,091	444,867	413,735	359,295	320,017	332,485	4,400,000
7	Net Expense (E)		355,991	319,736	325,769	293,886	384,405	414,723	435,091	444,867	413,735	359,295	320,017	332,485	4,400,000
8	Total System Recoverable Expenses (Lines 5 + 7)		337,039	300,784	306,817	274,934	365,453	395,771	416,139	425,915	394,783	340,343	301,065	313,533	
	a. Recoverable costs allocated to Energy		337,039	300,784	306,817	274,934	365,453	395,771	416,139	425,915	394,783	340,343	301,065	313,533	
	b. Recoverable costs allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	
9	Energy Jurisdictional Factor		0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600	
10	Demand Jurisdictional Factor		0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	
11	Retail Energy-Related Recoverable Costs (B)		326,436	291,114	297,668	267,140	355,045	384,725	404,945	414,070	383,326	329,980	291,371	304,428	4,050,247
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)		$ 326,436	$ 291,114	$ 297,668	$ 267,140	$ 355,045	$ 384,725	$ 404,945	$ 414,070	$ 383,326	$ 329,980	$ 291,371	$ 304,428	$ 4,050,247

Notes:

(A) Lines 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).
(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 2004 to December 2004
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 has completed environmental investigations and necessary remediations at six substations. A consent order has be executed between Progress Energy and the Florida Department of Environmental Protection that establishes a strategy to investigation and carry out needed remediation for the approximate 360 remaining substations in Progress Energy territory. The investigation activities are schedule to begin during the 3rd and 4th quarters of 2003. Finally, Progress Energy has identified certain pollution prevention activities that have been implemented via a written Best Management Practices Plan into the normal day to day work activities in substations. Further pollution prevention measures are currently being developed to ensure future releases at substations are minimized to the greatest extent possible.

Project Fiscal Expenditures:

See below

Project Progress Summary:

N/A

Project Projections:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $754,353.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
January 2004 to December 2004
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 has completed remedation on 752 distribution padmount transformer sites so far this year.

Project Fiscal Expenditures:

See below

Project Progress Summary:

N/A

Project Projections:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $5,168,353.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
January 2004 to December 2004
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 hazardous 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:
The planned upgrades are based on the Leak Detection Study which was completed in April 2003 and include the acquisition and installation of computer hardware and software for leak detection, modifications to the pipeline system to improve the accuracy, reliability, and sensitivity of the existing monitoring and detection system, installation of an additional communications circuit, upgrades to the Bartow meter station and related valve and piping work at the Anclote terminus.

Project Fiscal Expenditures:
The total estimated project costs for the last quarter of 2003 were $990,000 in capital investment and $10,000 in O&M expenses.

Project Progress Summary:
O&M expenses include the annual review and update of the integrity management plan and the risk analysis required by the new regulations. The capital investment includes for the design and implementation of an upgraded leak detection system required to comply with the new regulations.

Project Projections:

Estimated project O&M expenditures for the period January 2004 through December 2004 are expected to be $245,000.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
January 2004 to December 2004
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:
The installation of a secondary tank bottom at the Turner plant site, the addition of secondary containment for piping at the Bartow plant, and the upgrade of the dike field secondary containment system at the Crystal River Units 1 & 2 plant site have been scheduled for the the last quarter of 2003.

Project Fiscal Expenditures:
See below

Project Progress Summary:
The Company is in the final stages of developing a plan to upgrade the remaining storage tanks to comply with the secondary containment provisions of the rule. No additions of secondary tank bottoms have been scheduled for 2004, but PEF is preparing a timetable to ensure that the required improvements are implemented prior to 2010.

Project Projections:

There are no project expenditures estimated for the period January 2004 through December 2004.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
January 2004 to December 2004
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.

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 Fiscal Expenditures:
See below

Project Progress Summary:
N/A

Project Projections:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $4,400,000.

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)

Calculation of the Energy & Demand Allocation % by Rate Class

January 2004 to December 2004

Form 42-6P

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Projected Sales at Meter (mWh)	(3) Projected Avg 12 CP at Meter (MW)	(4) NCP Class Max Load Factor	(5) Delivery Efficiency Factor	(6) Projected Sales at Source (Generation) (mWh)	(7) Projected Avg 12 CP at Source (MW)	(8) Projected Sales at Source (Distrib Svc Only) (mWh)	(8) Class Max MW at Source Level (Distrib Svc)	(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	19,556,652	4,073.9	0.410	0.9358295	20,897,666	4,353.2	20,897,666	5,821.4	50.449%	57.393%	56.859%	58.564%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.609	1,321,155	247.6	0.434	0.9358295	1,411,748	264.6	1,411,748	371.5	3.408%	3.489%	3.483%	3.737%
Primary	0.609	8,178	1.5	0.434	0.9654000	8,471	1.6	8,471	2.2	0.020%	0.021%	0.021%	0.022%
Transmission	0.609	2,531	0.5	0.434	0.9754000	2,595	0.5	0	0.0	0.006%	0.006%	0.006%	0.000%
General Service													
GS-2 (Secondary)	1.000	82,245	9.4	1.000	0.9358295	87,885	10.0	87,885	10.0	0.212%	0.132%	0.138%	0.101%
General Service Demand													
GSD-1 Transmission	0.698	1,650	0.3	0.564	0.9754000	1,692	0.3	0	0.0	0.004%	0.004%	0.004%	0.000%
SS-1 Primary	3.733	1,762	0.1	0.186	0.9654000	1,825	0.1	1,825	1.1	0.004%	0.001%	0.001%	0.011%
Transmission	3.733	10,688	0.3	0.186	0.9754000	10,958	0.3	0	0.0	0.026%	0.004%	0.006%	0.000%
GSD-1 Secondary	0.698	12,293,545	2,010.6	0.564	0.9358295	13,136,522	2,148.4	13,136,522	2,657.8	31.713%	28.325%	28.585%	26.738%
Primary	0.698	2,708,093	442.9	0.564	0.9654000	2,805,151	458.8	2,805,151	567.6	6.772%	6.048%	6.104%	5.710%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	0.779	576	0.1	0.564	0.9358295	615	0.1	615	0.1	0.001%	0.001%	0.001%	0.001%
Primary	0.779	178,873	26.2	0.564	0.9654000	185,284	27.2	185,284	37.5	0.447%	0.358%	0.365%	0.377%
SS-3 (Primary)	0.480	2,618	0.6	0.025	0.9654000	2,712	0.6	2,712	12.6	0.007%	0.009%	0.008%	0.127%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.940	129,878	15.8	0.672	0.9358295	138,784	16.9	138,784	23.6	0.335%	0.222%	0.231%	0.237%
Primary	0.940	1,766,528	214.5	0.672	0.9654000	1,829,840	222.2	1,829,840	311.0	4.417%	2.930%	3.044%	3.129%
Transmission	0.940	489,311	59.4	0.672	0.9754000	501,652	60.9	0	0.0	1.211%	0.803%	0.835%	0.000%
SS-2 Primary	0.748	67,490	10.3	0.173	0.9654000	69,909	10.7	89,909	46.0	0.169%	0.141%	0.143%	0.463%
Transmission	0.748	3,617	0.6	0.173	0.9754000	3,708	0.6	0	0.0	0.009%	0.007%	0.008%	0.000%
Lighting													
LS-1 (Secondary)	4.650	305,074	7.5	0.479	0.9358295	325,993	8.0	325,993	77.7	0.787%	0.106%	0.158%	0.782%
		38,930,464	7,122.0			41,423,009	7,585.0	40,902,405	9,940.2	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 2003 to December 2003

(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 2002

(6) Column 2 x Column 5

(7) Column 3 x Column 5

(8) Calculated: Column 2 / (8,760 hours/ Column 4)/Column 5

(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

Docket No. 030007-EI
Progress Energy Florida
Exhibit _____ (JP-2)
Page 15 of 16

PROGRESS ENERGY FLORIDA Form 42-7P

Environmental Cost Recovery Clause (ECRC)

Calculation of the Energy & Demand Allocation % by Rate Class

January 2004 to December 2004

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)	50.449%	57.393%	56.859%	58.564%	$2,044,797	$434,198	$9,230,802	$301,548	$12,011,345	19,556,652	0.06142
General Service Non-Demand											
GS-1, GST-1											
Secondary	3.408%	3.489%	3.483%	3.737%	$138,137	$26,394	$589,063	$18,470	$772,064	1,321,155	0.05835
Primary	0.020%	0.021%	0.021%	0.022%	$829	$158	$3,535	$111	$4,633	8,096	0.05776
Transmission	0.006%	0.006%	0.006%	0.000%	$254	$49	$0	$34	$336	2,480	0.05718
TOTAL GS					**$139,220**	**$26,601**	**$592,598**	**$18,615**	**$777,033**	**1,331,732**	
General Service											
GS-2 (Secondary)	0.212%	0.132%	0.138%	0.101%	$8,599	$1,001	$15,908	$734	$26,242	82,245	0.03191
General Service Demand											
GSD-1 Transmission	0.004%	0.004%	0.004%	0.000%	$166	$28	$0	$20	$213	1,617	0.04656
SS-1 Primary	0.004%	0.001%	0.001%	0.011%	$179	$6	$1,774	$5	$1,964	1,744	0.04704
Transmission	0.026%	0.004%	0.006%	0.000%	$1,072	$33	$0	$32	$1,138	10,474	0.04656
GSD-1 Secondary	31.713%	28.325%	28.585%	26.738%	$1,285,384	$214,287	$4,214,439	$151,601	$5,865,711	12,293,545	0.04751
Primary	6.772%	6.048%	6.104%	5.710%	$274,479	$45,758	$899,944	$32,373	$1,252,554	2,681,012	0.04704
TOTAL GSD					**$1,561,279**	**$260,112**	**$5,116,158**	**$184,031**	**$7,121,580**	**14,988,393**	
Curtailable											
CS-1, CST-1, CS-2, CST-2, SS-3											
Secondary	0.001%	0.001%	0.001%	0.001%	$60	$9	$197	$6	$273	576	0.05705
Primary	0.447%	0.358%	0.365%	0.377%	$18,130	$2,708	$59,440	$1,935	$82,213	177,084	0.05648
SS-3 (Primary)	0.007%	0.009%	0.008%	0.127%	$265	$64	$19,970	$44	$20,344	2,592	0.05648
TOTAL CS					**$18,455**	**$2,781**	**$79,608**	**$1,986**	**$102,830**	**180,252**	
Interruptible											
IS-1, IST-1, IS-2, IST-2											
Secondary	0.335%	0.222%	0.231%	0.237%	$13,580	$1,681	$37,405	$1,224	$53,890	129,878	0.37300
Primary	4.417%	2.930%	3.044%	3.129%	$179,046	$22,164	$493,180	$16,145	$710,536	1,748,863	0.36927
Transmission	1.211%	0.803%	0.835%	0.000%	$49,086	$6,076	$0	$4,426	$59,588	479,525	0.36554
SS-2 Primary	0.169%	0.141%	0.143%	0.463%	$6,840	$1,064	$72,978	$757	$81,640	66,815	0.36927
Transmission	0.009%	0.007%	0.008%	0.000%	$363	$56	$0	$40	$459	3,545	0.36554
					$248,915	**$31,042**	**$603,563**	**$22,593**	**$906,113**	**2,428,625**	
Lighting											
LS-1 (Secondary)	0.787%	0.106%	0.158%	0.782%	$31,898	$798	$123,191	$838	$156,725	305,074	0.05137
	100.000%	100.000%	100.000%	100.000%	$4,053,163	$756,534	$15,761,828	$530,345	$21,101,869	38,872,973	0.05428

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 2004 to December 2004

(11) Column 7/ Column 8 x 100

Form Appendix
Revised 10/17/03

EXHIBIT __ (JP-3)

ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1P THROUGH 42-7P

JANUARY 2004 - DECEMBER 2004

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

Form 42-1P
Revised 10/17/03

For the Projected Period
January 2004 to December 2004

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)	$4,270,969	$525,973	$5,144,010	$225,028	$10,165,980
	b Projected Capital Projects (Form 42-3P, Lines 7 through 9)	(220,723)	0	0	291,277	70,554
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	4,050,247	525,973	5,144,010	516,304	10,236,534
2	True-up for Estimated Over/(Under) Recovery for the current period January 2003 through December 2003 (Form 42-2E, Line 5 + 6 + 10)	0	(229,347)	(10,571,117)	(22,480)	($10,822,944)
3	Final True-up for the period January 2002 to December 2002 (Form 42-1A, Line 3)	0	(729)	(38,104)	0	($38,833)
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection period January 2004 to December 2004 (Line 1 - Line 2 - Line 3)	4,050,247	756,049	15,753,231	538,784	21,098,311
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of .00072)	4,053,163	756,594	15,764,573	539,172	$21,113,502

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 to December 2004

Form 42-2P
Revised 10/17/03

O&M Activities
(in Dollars)

Line	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	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	62,863	62,863	62,863	62,863	62,863	62,863	62,863	62,863	62,863	62,863	62,863	62,863	754,353	754,353	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	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	5,168,353	5,168,353	0
3a Pipeline Integrity Management, Review/Update Plan and Risk Assessments	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	245,000	245,000	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	355,991	319,736	325,769	293,886	384,405	414,723	435,091	444,867	413,735	359,295	320,017	332,485	4,400,000	0	4,400,000
2 Total of O&M Activities	867,883	831,628	837,661	805,778	896,297	926,615	946,983	956,759	925,627	871,187	831,909	844,377	10,542,706	$6,142,706	$4,400,000
3 Recoverable Costs Allocated to Energy	355,991	319,736	325,769	293,886	384,405	414,723	435,091	444,867	413,735	359,295	320,017	332,485	4,400,004		
4 Recoverable Costs Allocated to Demand - Transm	60,779	60,779	60,779	60,779	60,779	60,779	60,779	60,779	60,779	60,779	60,779	60,779	729,353		
Recoverable Costs Allocated to Demand - Distrib	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	430,696	5,168,353		
Recoverable Costs Allocated to Demand - Production	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	20,417	245,000		
5 Retail Energy Jurisdictional Factor	0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709600	0.9695500	0.9678000	0.9709600			
6 Retail Transmission Demand Jurisdictional Factor	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500	0.7211500			
Retail Distribution Demand Jurisdictional Factor	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900	0.9952900			
Retail Production Demand Jurisdictional Factor	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800	0.9184800			
7 Jurisdictional Energy Recoverable Costs (A)	344,792	309,456	316,055	285,554	373,457	403,148	423,387	432,495	401,728	348,354	309,712	322,830	4,270,969		
8 Jurisdictional Demand Recoverable Costs - Transm (B)	43,831	43,831	43,831	43,831	43,831	43,831	43,831	43,831	43,831	43,831	43,831	43,831	525,973		
Jurisdictional Demand Recoverable Costs - Distrib (B)	428,668	428,668	428,668	428,668	428,668	428,668	428,668	428,668	428,668	428,668	428,668	428,668	5,144,010		
Jurisdictional Demand Recoverable Costs - Production (B)	18,752	18,752	18,752	18,752	18,752	18,752	18,752	18,752	18,752	18,752	18,752	18,752	225,028		
9 Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$836,042	$800,707	$807,305	$776,805	$864,708	$894,399	$914,638	$923,746	$892,979	$839,605	$800,963	$814,081	$10,165,980		

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

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 to December 2004

Form 42-3P
Revised 10/17/03

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	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	15,426	15,387	15,351	15,313	15,274	15,238	15,200	15,163	15,125	15,087	15,050	15,012	182,626	$182,626	$0
4a Above Ground Tank Secondary Containment - Turner CTs	8,426	8,400	8,375	8,348	8,323	8,297	8,271	8,245	8,220	8,193	8,168	8,142	99,408	99,408	0
4b Above Ground Tank Secondary Containment - Bartow CTs	1,575	1,569	1,564	1,559	1,553	1,547	1,542	1,536	1,530	1,525	1,520	1,515	18,535	18,535	0
4c Above Ground Tank Secondary Containment - Crystal River 1&2	1,687	1,681	1,676	1,670	1,665	1,660	1,654	1,648	1,643	1,637	1,631	1,626	19,878	19,878	0
5 SO_2 Emissions Allowances	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(227,424)	0	(227,424)
2 Total Investment Projects - Recoverable Costs	8,162	8,085	8,014	7,938	7,863	7,790	7,715	7,640	7,566	7,490	7,417	7,343	93,023	$320,447	($227,424)
3 Recoverable Costs Allocated to Energy	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(227,424)		
4 Recoverable Costs Allocated to Demand	27,114	27,037	26,966	26,890	26,815	26,742	26,667	26,592	26,518	26,442	26,369	26,295	320,447		
5 Retail Energy Jurisdictional Factor	0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600			
6 Retail Demand Jurisdictional Factor	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700			
7 Jurisdictional Energy Recoverable Costs (B)	(18,356)	(18,343)	(18,387)	(18,415)	(18,412)	(18,423)	(18,442)	(18,425)	(18,402)	(18,375)	(18,342)	(18,402)	(220,723)		
8 Jurisdictional Demand Recoverable Costs - Production - Base (C)	24,646	24,576	24,511	24,442	24,374	24,308	24,240	24,171	24,104	24,035	23,969	23,901	291,277		
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$6,290	$6,233	$6,124	$6,027	$5,962	$5,885	$5,797	$5,746	$5,702	$5,660	$5,627	$5,500	$70,554		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 14
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Docket No. 030007-EI
Progress Energy Florida
Exhibit (JP-3)
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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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
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. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	$989,994	989,994	989,994	989,994	989,994	989,994	989,994	989,994	989,994	989,994	989,994	989,994	989,994	
3	Less: Accumulated Depreciation (C)	(2,970)	(5,940)	(8,910)	(11,880)	(14,850)	(17,820)	(20,790)	(23,760)	(26,730)	(29,700)	(32,670)	(35,640)	(38,610)	
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)	$987,024	984,054	981,084	978,114	975,144	972,174	969,204	966,234	963,264	960,294	957,324	954,354	951,384	
6	Average Net Investment		985,539	982,569	979,599	976,629	973,659	970,689	967,719	964,749	961,779	958,809	955,839	952,869	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (D)		8,829	8,802	8,776	8,749	8,722	8,696	8,669	8,643	8,616	8,589	8,563	8,536	$104,190
	b. Debt Component - 2.57%		2,111	2,104	2,098	2,092	2,085	2,079	2,073	2,066	2,060	2,053	2,047	2,041	24,909
8	Investment Expenses														
	a. Depreciation - 3.6% (E)		2,970	2,970	2,970	2,970	2,970	2,970	2,970	2,970	2,970	2,970	2,970	2,970	35,640
	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)		1,516	1,511	1,507	1,502	1,497	1,493	1,488	1,484	1,479	1,475	1,470	1,465	17,887
	e. Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		15,426	15,387	15,351	15,313	15,274	15,238	15,200	15,163	15,125	15,087	15,050	15,012	182,626
	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		15,426	15,387	15,351	15,313	15,274	15,238	15,200	15,163	15,125	15,087	15,050	15,012	182,626
10	Energy Jurisdictional Factor		0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600	
11	Demand Jurisdictional Factor		0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	
12	Retail Energy-Related Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Costs (I)		14,022	13,986	13,954	13,919	13,884	13,851	13,816	13,783	13,748	13,714	13,680	13,645	166,002
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 14,022	$ 13,986	$ 13,954	$ 13,919	$ 13,884	$ 13,851	$ 13,816	$ 13,783	$ 13,748	$ 13,714	$ 13,680	$ 13,645	$ 166,002

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 @ $0 and end of period @ $989,994 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) Lines 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 for Bartow/Anclote Pipeline project. 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)

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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
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. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	$502,700	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)	(2,011)	(4,022)	(6,033)	(8,043)	(10,054)	(12,065)	(14,076)	(16,087)	(18,097)	(20,108)	(22,119)	(24,130)	(26,141)	
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)	$500,689	498,678	496,667	494,657	492,646	490,635	488,624	486,613	484,603	482,592	480,581	478,570	476,559	
6	Average Net Investment		499,684	497,673	495,662	493,651	491,640	489,630	487,619	485,608	483,597	481,586	479,576	477,565	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (D)		4,476	4,458	4,440	4,422	4,404	4,386	4,368	4,350	4,332	4,314	4,296	4,278	$52,524
	b. Debt Component - 2.57%		1,070	1,066	1,062	1,057	1,053	1,049	1,044	1,040	1,036	1,031	1,027	1,023	12,558
8	Investment Expenses														
	a. Depreciation - 4.8% (E)		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 (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)		869	866	862	859	855	852	848	845	841	837	834	830	10,197
	e. Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		8,426	8,400	8,375	8,348	8,323	8,297	8,271	8,245	8,220	8,193	8,168	8,142	99,409
	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		8,426	8,400	8,375	8,348	8,323	8,297	8,271	8,245	8,220	8,193	8,168	8,142	99,408
10	Energy Jurisdictional Factor		0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600	
11	Demand Jurisdictional Factor		0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	
12	Retail Energy-Related Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Costs (I)		7,659	7,635	7,613	7,588	7,565	7,542	7,518	7,494	7,472	7,447	7,424	7,401	90,359
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 7,659	$ 7,635	$ 7,613	$ 7,588	$ 7,565	$ 7,542	$ 7,518	$ 7,494	$ 7,472	$ 7,447	$ 7,424	$ 7,401	$ 90,359

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 @ $0 and end of period @ $502,700 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) Lines 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 for Above Ground Tank Secondary Containment - Turner CTs project. 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
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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
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. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	$91,100	91,100	91,100	91,100	91,100	91,100	91,100	91,100	91,100	91,100	91,100	91,100	91,100	
3	Less: Accumulated Depreciation (C)	(433)	(866)	(1,298)	(1,731)	(2,164)	(2,597)	(3,029)	(3,462)	(3,895)	(4,328)	(4,760)	(5,193)	(5,626)	
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)	$90,667	90,234	89,802	89,369	88,936	88,503	88,071	87,638	87,205	86,772	86,340	85,907	85,474	
6	Average Net Investment		90,451	90,018	89,585	89,152	88,720	88,287	87,854	87,422	86,989	86,556	86,123	85,691	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (D)		810	806	803	799	795	791	787	783	779	775	772	768	$9,468
	b. Debt Component - 2.57%		194	193	192	191	190	189	188	187	186	185	184	184	2,263
8	Investment Expenses														
	a. Depreciation - 5.7% (E)		433	433	433	433	433	433	433	433	433	433	433	433	5,193
	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)		138	137	137	136	135	135	134	133	133	132	131	131	1,611
	e. Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,575	1,569	1,564	1,559	1,553	1,547	1,542	1,536	1,530	1,525	1,520	1,515	18,535
	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		1,575	1,569	1,564	1,559	1,553	1,547	1,542	1,536	1,530	1,525	1,520	1,515	18,535
10	Energy Jurisdictional Factor		0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600	
11	Demand Jurisdictional Factor		0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	
12	Retail Energy-Related Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Costs (I)		1,432	1,426	1,422	1,417	1,412	1,406	1,402	1,396	1,391	1,386	1,382	1,377	16,848
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 1,432	$ 1,426	$ 1,422	$ 1,417	$ 1,412	$ 1,406	$ 1,402	$ 1,396	$ 1,391	$ 1,386	$ 1,382	$ 1,377	$ 16,848

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 @ $0 and end of period @ $91,900 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) Lines 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 5.7% 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 for Above Ground Tank Secondary Containment - Bartow CTs project. 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
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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
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. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	$100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	
3	Less: Accumulated Depreciation (C)	(1,104)	(1,546)	(1,987)	(2,429)	(2,871)	(3,312)	(3,754)	(4,196)	(4,637)	(5,079)	(5,521)	(5,962)	(6,404)	
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)	$98,896	98,454	98,013	97,571	97,129	96,688	96,246	95,804	95,363	94,921	94,479	94,038	93,596	
6	Average Net Investment		98,675	98,234	97,792	97,350	96,909	96,467	96,025	95,584	95,142	94,700	94,259	93,817	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (D)		884	880	876	872	868	864	860	856	852	848	844	840	$10,344
	b. Debt Component - 2.57%		211	210	209	208	208	207	206	205	204	203	202	201	2,474
8	Investment Expenses														
	a. Depreciation - 5.3% (E)		442	442	442	442	442	442	442	442	442	442	442	442	5,300
	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)		150	150	149	148	148	147	146	146	145	144	144	143	1,761
	e. Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,687	1,681	1,676	1,670	1,665	1,660	1,654	1,648	1,643	1,637	1,631	1,626	19,879
	a. Recoverable Costs Allocated to Energy		-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand		1,687	1,681	1,676	1,670	1,665	1,660	1,654	1,648	1,643	1,637	1,631	1,626	19,878
10	Energy Jurisdictional Factor		0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600	
11	Demand Jurisdictional Factor		0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	
12	Retail Energy-Related Costs (H)		-	-	-	-	-	-	-	-	-	-	-	-	-
13	Retail Demand-Related Costs (I)		1,533	1,528	1,523	1,518	1,513	1,509	1,503	1,498	1,493	1,488	1,483	1,478	18,069
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 1,533	$ 1,528	$ 1,523	$ 1,518	$ 1,513	$ 1,509	$ 1,503	$ 1,498	$ 1,493	$ 1,488	$ 1,483	$ 1,478	$ 18,069

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 @ $0 and end of period @ $100,000 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) Lines 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 for Above Ground Tank Secondary Containment - Crystal River 1&2 project. 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
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2004 to December 2004

Form 42-4P
Page 5 of 5
Revised 10/17/03

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

Line	Description	Beginning of Period Amount	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
1	Working Capital Dr (Cr)														
	a. 1581001 SO_2 Emission Allowance Inventory	$ -	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	b. 25401FL Auctioned SO_2 Allowance	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	
2	Total Working Capital	$ (1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	($1,707,393)	
3	Average Net Investment		(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	(1,707,393)	
4	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,295)	(15,296)	(15,295)	($183,540)
	b. Debt Component - 2.57%		(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(3,657)	(43,884)
5	Total Return Component (D)		(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(18,952)	(227,424)
6	Expense Dr (Cr)														
	a. 5090001 SO_2 allowance expense		355,991	319,736	325,769	293,886	384,405	414,723	435,091	444,867	413,735	359,295	320,017	332,485	4,400,000
7	Net Expense (E)		355,991	319,736	325,769	293,886	384,405	414,723	435,091	444,867	413,735	359,295	320,017	332,485	4,400,000
8	Total System Recoverable Expenses (Lines 5 + 7)		337,039	300,784	306,817	274,934	365,453	395,771	416,139	425,915	394,783	340,343	301,065	313,533	
	a. Recoverable costs allocated to Energy		337,039	300,784	306,817	274,934	365,453	395,771	416,139	425,915	394,783	340,343	301,065	313,533	
	b. Recoverable costs allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	
9	Energy Jurisdictional Factor		0.9685400	0.9678500	0.9701800	0.9716500	0.9715200	0.9720900	0.9731000	0.9721900	0.9709800	0.9695500	0.9678000	0.9709600	
10	Demand Jurisdictional Factor		0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	0.9089700	
11	Retail Energy-Related Recoverable Costs (B)		326,436	291,114	297,668	267,140	355,045	384,725	404,945	414,070	383,326	329,980	291,371	304,428	4,050,247
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)		$ 326,436	$ 291,114	$ 297,668	$ 267,140	$ 355,045	$ 384,725	$ 404,945	$ 414,070	$ 383,326	$ 329,980	$ 291,371	$ 304,428	$ 4,050,247

Notes:
(A) Lines 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).
(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

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Progress Energy Florida
Exhibit (JP-3)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
January 2004 to December 2004
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 has completed environmental investigations and necessary remediations at six substations. A consent order has be executed between Progress Energy and the Florida Department of Environmental Protection that establishes a strategy to investigation and carry out needed remediation for the approximate 360 remaining substations in Progress Energy territory. The investigation activities are schedule to begin during the 3rd and 4th quarters of 2003. Finally, Progress Energy has identified certain pollution prevention activities that have been implemented via a written Best Management Practices Plan into the normal day to day work activities in substations. Further pollution prevention measures are currently being developed to ensure future releases at substations are minimized to the greatest extent possible.

Project Fiscal Expenditures:

See below

Project Progress Summary:

N/A

Project Projections:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $754,353.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
January 2004 to December 2004
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Distribution System Environmental Investigation, Remediation, and Pollution Preventior
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 has completed remedation on 752 distribution padmount transformer sites so far this year.

Project Fiscal Expenditures:
See below

Project Progress Summary:
N/A

Project Projections:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $5,168,353.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
January 2004 to December 2004
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:
The planned upgrades are based on the Leak Detection Study which was completed in April 2003 and include the acquisition and installation of computer hardware and software for leak detection, modifications to the pipeline system to improve the accuracy, reliability, and sensitivity of the existing monitoring and detection system, installation of an additional communications circuit, upgrades to the Bartow meter station and related valve and piping work at the Anclote terminus.

Project Fiscal Expenditures:
The total estimated project costs for the last quarter of 2003 were $990,000 in capital investment and $10,000 in O&M expenses.

Project Progress Summary:
O&M expenses include the annual review and update of the integrity management plan and the risk analysis required by the new regulations. The capital investment includes for the design and implementation of an upgraded leak detection system required to comply with the new regulations.

Project Projections:

Estimated project O&M expenditures for the period January 2004 through December 2004 are expected to be $245,000.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
January 2004 to December 2004
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:
The installation of a secondary tank bottom at the Turner plant site, the addition of secondary containment for piping at the Bartow plant, and the upgrade of the dike field secondary containment system at the Crystal River Units 1 & 2 plant site have been scheduled for the the last quarter of 2003.

Project Fiscal Expenditures:
See below

Project Progress Summary:
The Company is in the final stages of developing a plan to upgrade the remaining storage tanks to comply with the secondary containment provisions of the rule. No additions of secondary tank bottoms have been scheduled for 2004, but PEF is preparing a timetable to ensure that the required improvements are implemented prior to 2010.

Project Projections:

There are no project expenditures estimated for the period January 2004 through December 2004.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
January 2004 to December 2004
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.

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 Fiscal Expenditures:
See below

Project Progress Summary:
N/A

Project Projections:

Estimated project expenditures for the period January 2004 through December 2004 are expected to be $4,400,000.

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)

Calcualtion of the Energy & Demand Allocation % by Rate Class

January 2004 to December 2004

Form 42-6P
Revised 10/17/03

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Projected Sales at Meter (mWh)	(3) Projected Avg 12 CP at Meter (MW)	(4) NCP Class Max Load Factor	(5) Delivery Efficiency Factor	(6) Projected Sales at Source (Generation) (mWh)	(7) Projected Avg 12 CP at Source (MW)	7(a) Projected Sales at Source (Distrib Svc Only) (mWh)	(8) Class Max MW at Source Level (Distrib Svc)	(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	19,556,652	4,073.9	0.40979	0.9358295	20,897,666	4,353.2	20,897,666	5,821.4	50.449%	57.393%	56.859%	58.564%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.609	1,321,155	247.6	0.43381	0.9358295	1,411,748	264.6	1,411,748	371.5	3.408%	3.489%	3.483%	3.737%
Primary	0.609	8,178	1.5	0.43381	0.9654000	8,471	1.6	8,471	2.2	0.020%	0.021%	0.021%	0.022%
Transmission	0.609	2,531	0.5	0.43381	0.9754000	2,595	0.5	0	0.0	0.006%	0.006%	0.006%	0.000%
General Service													
GS-2 (Secondary)	1.000	82,245	9.4	1.00000	0.9358295	87,885	10.0	87,885	10.0	0.212%	0.132%	0.138%	0.101%
General Service Demand													
GSD-1 Transmission	0.698	1,650	0.3	0.56422	0.9754000	1,692	0.3	0	0.0	0.004%	0.004%	0.004%	0.000%
SS-1 Primary	3.733	1,762	0.1	0.18621	0.9654000	1,825	0.1	1,825	1.1	0.004%	0.001%	0.001%	0.011%
Transmission	3.733	10,688	0.3	0.18621	0.9754000	10,958	0.3	0	0.0	0.026%	0.004%	0.006%	0.000%
GSD-1 Secondary	0.698	12,293,545	2,010.6	0.56422	0.9358295	13,136,522	2,148.4	13,136,522	2,657.8	31.713%	28.325%	28.585%	26.738%
Primary	0.698	2,708,093	442.9	0.56422	0.9654000	2,805,151	458.8	2,805,151	567.6	6.772%	6.048%	6.104%	5.710%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	0.779	576	0.1	0.56424	0.9358295	615	0.1	615	0.1	0.001%	0.001%	0.001%	0.001%
Primary	0.779	178,873	26.2	0.56424	0.9654000	185,284	27.2	185,284	37.5	0.447%	0.358%	0.365%	0.377%
SS-3 (Primary)	0.480	2,618	0.6	0.02458	0.9654000	2,712	0.6	2,712	12.6	0.007%	0.009%	0.008%	0.127%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.940	129,878	15.8	0.67161	0.9358295	138,784	16.9	138,784	23.6	0.335%	0.222%	0.231%	0.237%
Primary	0.940	1,766,528	214.5	0.67161	0.9654000	1,829,840	222.2	1,829,840	311.0	4.417%	2.930%	3.044%	3.129%
Transmission	0.940	489,311	59.4	0.67161	0.9754000	501,652	60.9	0	0.0	1.211%	0.803%	0.835%	0.000%
SS-2 Primary	0.748	67,490	10.3	0.17340	0.9654000	69,909	10.7	69,909	46.0	0.169%	0.141%	0.143%	0.463%
Transmission	0.748	3,617	0.6	0.17340	0.9754000	3,708	0.6	0	0.0	0.009%	0.007%	0.008%	0.000%
Lighting													
LS-1 (Secondary)	4.650	305,074	7.5	0.47900	0.9358295	325,993	8.0	325,993	77.7	0.787%	0.106%	0.158%	0.782%
		38,930,464	7,122.0			41,423,009	7,585.0	40,902,405	9,940.2	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 2003 to December 2003
(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 2002
(6) Column 2 x Column 5
(7) Column 3 x 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
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % by Rate Class
January 2004 to December 2004

Form 42-7P
Revised 10/17/03

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)	50.449%	57.393%	56.859%	58.564%	$2,044,797	$434,232	$9,232,410	$306,567	$12,018,006	19,556,652	0.061
General Service Non-Demand											
GS-1, GST-1											
Secondary	3.408%	3.489%	3.483%	3.737%	$138,137	$26,396	$589,166	$18,777	$772,476	1,321,155	0.058
Primary	0.020%	0.021%	0.021%	0.022%	$829	$158	$3,535	$113	$4,635	8,096	0.057
Transmission	0.006%	0.006%	0.006%	0.000%	$254	$49	$0	$35	$337	2,480	0.057
TOTAL GS					**$139,220**	**$26,603**	**$592,701**	**$18,925**	**$777,448**	**1,331,732**	
General Service											
GS-2 (Secondary)	0.212%	0.132%	0.138%	0.101%	$8,599	$1,001	$15,911	$746	$26,257	82,245	0.032
General Service Demand											
GSD-1 Transmission	0.004%	0.004%	0.004%	0.000%	$166	$28	$0	$20	$213	1,617	0.047
SS-1 Primary	0.004%	0.001%	0.001%	0.011%	$179	$6	$1,775	$5	$1,964	1,744	0.048
Transmission	0.026%	0.004%	0.006%	0.000%	$1,072	$33	$0	$33	$1,139	10,474	0.047
GSD-1 Secondary	31.713%	28.325%	28.585%	26.738%	$1,285,384	$214,304	$4,215,173	$154,125	$5,868,986	12,293,545	0.048
Primary	6.772%	6.048%	6.104%	5.710%	$274,479	$45,762	$900,101	$32,912	$1,253,254	2,681,012	0.048
TOTAL GSD					**$1,561,279**	**$260,132**	**$5,117,049**	**$187,095**	**$7,125,555**	**14,988,393**	
Curtailable											
CS-1, CST-1, CS-2, CST-2, SS-3											
Secondary	0.001%	0.001%	0.001%	0.001%	$60	$9	$197	$7	$273	576	0.057
Primary	0.447%	0.358%	0.365%	0.377%	$18,130	$2,708	$59,450	$1,967	$82,256	177,084	0.056
SS-3 (Primary)	0.007%	0.009%	0.008%	0.127%	$265	$64	$19,974	$45	$20,349	2,592	0.056
TOTAL CS					**$18,455**	**$2,782**	**$79,622**	**$2,019**	**$102,877**	**180,252**	
Interruptible											
IS-1, IST-1, IS-2, IST-2											
Secondary	0.335%	0.222%	0.231%	0.237%	$13,580	$1,681	$37,412	$1,245	$53,917	129,878	0.037
Primary	4.417%	2.930%	3.044%	3.129%	$179,046	$22,166	$493,266	$16,413	$710,892	1,748,863	0.037
Transmission	1.211%	0.803%	0.835%	0.000%	$49,086	$6,077	$0	$4,500	$59,662	479,525	0.036
SS-2 Primary	0.169%	0.141%	0.143%	0.463%	$6,840	$1,064	$72,990	$770	$81,665	66,815	0.037
Transmission	0.009%	0.007%	0.008%	0.000%	$363	$56	$0	$41	$460	3,545	0.036
					$248,915	**$31,045**	**$603,668**	**$22,969**	**$906,597**	**2,428,625**	
Lighting											
LS-1 (Secondary)	0.787%	0.106%	0.158%	0.782%	$31,898	$798	$123,213	$852	$156,760	305,074	0.051
	100.000%	100.000%	100.000%	100.000%	$4,053,163	$756,594	$15,764,573	$539,172	$21,113,502	38,872,973	0.054

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 2004 to December 2004
(11) Column 7/ Column 8 x 100

Department of Environmental Protection

Jeb Bush
Governor

Central District
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767

David B. Struhs
Secretary

June 4, 2003

By HAND DELIVERY

Sarah S. Rogers, P.E.
Vice President, Transmission
Progress Energy Florida
3300 Exchange Place
Lake Mary, FL 32746-5413

Re: Proposed Settlement by Short Form Consent Order of
Progress Energy Florida Substations
OGC File No.: 03-0771

Dear Ms. Rogers:

The purpose of this letter is to complete the resolution of the matters previously identified by the Department in the Warning Letters dated September 12, 2002, (248604 Southwest District), and November 4, 2002, (OWL-HW-C/E-02-029, Central District) copies of which are attached. The Department finds that you are in violation of the rules and statutes cited in the attached Warning Letters.

In order to resolve the matters identified in the attached Warning Letters, you are assessed civil penalties in the amount of $16,274.00, along with $1,000.00 to reimburse Department costs, for a total of $17,274.00. The civil penalty in this case includes one violation with a penalty of $2,000.00 or more. Payment shall be sent to the Department of Environmental Protection, Central District, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767, within 30 days of the Department countersigning this letter. Payment must be made by cashier's check or money order. The instrument shall be made payable to the "Department of Environmental Protection" and shall include thereon the OGC number assigned to this Consent Order and the notation "Ecosystem Management and Restoration Trust Fund".

In addition, Progress Energy Florida (PEF) shall implement Best Management Practices (BMPs), Inspection Plans, Substation Waste Disposal Plans, and Remedial Action Plans (Plans) in order to address those areas of non-compliance determined during the inspections as described in both of the attached Warning Letters. The schedule for developing and implementing such BMPs and Plans is set forth in Exhibit "A." All BMPS, Plans and related documents shall be sent to Douglas Outlaw, Department of Environmental Protection, Hazardous Waste Regulation Section, 2600 Blairstone Road, MS #4560, Tallahassee, Florida 32399-2400.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030007-EI EXHIBIT NO. Comp. Ex 5
COMPANY/ Progress Energy FL
WITNESS. Kent D. Hedrick, KDH-1+2
DATE: 11-12-03

The Department reserves the right to conduct enforcement on PEF for violations of applicable law, rule, or this Order, if PEF does not submit Plans or, once approved, implement the Plans in the manner and within the time frames specified in Exhibit A. In any administrative proceeding instituted by the Department pursuant to Sections 120.569 and 120.57, Florida Statutes (F.S.), in which the Department alleges that Respondent is in violation of applicable law or rule, the Department shall have the burden of proof. Correspondingly, PEF reserves all of its rights and defenses, under Chapter 120, F.S., or otherwise, to respond to any such Department enforcement action. With regard to any agency action taken by the Department concerning submission or implementation of the Plans submitted by the Respondent to the Department as required by Exhibit A, the Respondent may file a Petition for Formal or Informal Administrative Hearing. The Respondent shall have the burden of proving that the Department's determination was unreasonable or inappropriate. If both parties agree, the Department and PEF may mediate any dispute as provided in Section 120.572, F.S. If the parties agree to mediation, the time for filing a petition for a formal administrative hearing under Chapter 120, F.S., pursuant to this paragraph, is tolled until such time as the mediation is unsuccessful. No penalties shall accrue against PEF after the parties agree to mediation and until such time that PEF receives notice from the Department that the mediation is unsuccessful. PEF shall have 21 days from receipt of such notice within which to file its petition for formal administrative hearing as referenced herein.

Your signing this letter constitutes your acceptance of the Department's offer to resolve this matter on these terms. If you elect to sign this letter, please return it to the Department at the address indicated above. The Department will then countersign the letter and file it with the Clerk of the Department. When the signed letter is filed with the Clerk, the letter shall constitute final agency action of the Department, which shall be enforceable pursuant to Sections 120.69 and 403.121, F.S.

Florida Power Corporation d/b/a Progress Energy Florida, Inc. does not admit, by signature of this letter, or actions taken hereunder, that it has violated any statute or rule promulgated by the Department or the U.S. Environmental Protection Agency. The parties are entering into this Consent Order to complete settlement of the violations alleged by the Department.

If you do not sign and return this letter to the Department at the District address by June 4, 2003, the Department will assume that you are not interested in settling this matter on the above described terms, and will proceed accordingly. None of your rights or substantial interests are determined by this letter unless you sign it and it is filed with the Department Clerk.

Sincerely,

Vivian F. Garfein
Director, Central District

FOR THE RESPONDENTS:

I, Sarah S. Rogers, on behalf of Progress Energy Florida, **HEREBY ACCEPT THE TERMS OF THE SETTLEMENT OFFER IDENTIFIED ABOVE.**

By: _____

Date: 6/4/03

FOR DEPARTMENT USE ONLY

DONE AND ENTERED this 4th day of June, 2003.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

_____
Vivian Garfein
Director, Central District

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to
§120.52, Florida Statutes,
With the designated Department
Clerk, receipt of which is hereby
Acknowledged.

_____ 6/4/2003
Clerk Date

Copies furnished to:

ATTACHMENT A

PREPARATION SCHEDULE for
INSPECTION, WASTE DISPOSAL, and
REMEDIAL ACTION PLANS and
BEST MANAGEMENT PRACTICES at
PROGRESS ENERGY FLORIDA SUBSTATIONS

Inspections were conducted at Florida Power Corporation d/b/a/ Progress Energy Florida, Inc. (PEF) substations in 2002 by the Florida Department of Environmental Protection (FDEP) in four FDEP districts (Northeast, Central, Southwest and South). As agreed with FDEP, PEF is developing and implementing Best Management Practices (BMPs) to prevent and detect the release of dielectric fluids and other pollutants, if any, at substations and Inspection, Waste Disposal and Remedial Action Plans (Plans) to address remediation of past, present and future releases of dielectric fluid and other pollutants, if any, to the environment. The BMPs will upgrade maintenance, release prevention, and internal inspection programs. The Plans will address sampling activities, remedial action planning, waste profiling, and waste disposal activities at PEF substations and include reasonable timeframes for completing each task in the Plans. The BMPs and the Plans (as indicated below) will be submitted for review and approval by the FDEP and will be implemented consistently at all PEF owned or maintained substations located within Florida. Below is a list of proposed Plans and BMPs, along with a schedule for preparation and submittal of these documents to FDEP for approval. Each Plan and BMP will include implementation details along with an implementation schedule. FDEP will provide comments, as necessary, to PEF within 60 days of receipt of the proposed Plans and BMPs. Within 30 days of receipt of comments from the FDEP, PEF will submit appropriately modified plans, as necessary, to the FDEP for approval. The releases of dielectric fluid and other pollutants if any, from operations and maintenance shall be remediated to applicable Department approved standards or target levels, taking into account Risk-Based Corrective Action concepts or principles as they may be applicable to any PEF substations.

Plan/BMP Title	*Submittal Date*
Release Prevention BMP (submitted on 2/28/03)	February 28, 2003
Substation Operation and Maintenance BMP (submitted on 2/28/03)	March 15, 2003
Substation Inspection Plan	30 days after Consent Order effective date
Substation Waste Disposal Plan	30 days after Consent Order effective date
Substation Assessment and Remedial Action Plan	60 days after Consent Order effective date

BEST MANAGEMENT PRACTICES
Progress Energy Florida substations

Progress Energy Florida is addressing release prevention of dielectric fluid at substations by development and implementation of Best Management Practices (BMPs) to prevent and detect the release of dielectric fluids. The development and implementation of these BMPs are consistent with PEF's Environmental Management System (EMS) and environmental policy. The policy includes commitments to comply with applicable environmental laws and regulations, pollution prevention, and to be prepared to act effectively and in a timely fashion in the event of an environmental emergency. The BMPs will upgrade maintenance, release prevention, and internal inspection programs. BMPs will be continually reviewed and updated as appropriate. In the future, additional BMP's will be developed and implemented as needed.

Release Prevention Best Management Practices

The following BMPs are included in our plan of action pertaining to release prevention of dielectric insulating fluid at substations:

- Spill Prevention, Control, and Countermeasure (SPCC) Plans have been developed for all substation sites located near navigable waters. Installation or improvements of containment structures are being conducted at 78 substations. As a BMP, plans have also been developed for all other substations determined not to require SPCC plans.

- Major and minor alarm systems are in place to alert crews to substation equipment problems that could result in equipment failure and a release of dielectric fluid. Crews are on-call 24 hours a day/ 7 days a week to respond to alarms and prevent or minimize potential releases.

- Valves and fittings are regularly inspected so that preventative maintenance can be performed on these components before releases to the environment occur.

- Substation maintenance vehicles carry spill control equipment. For example, pads and absorbent materials are used to manage operational leaks and small releases. Shovels are carried to construct earthen berms in the event of larger releases.

- Substation maintenance crews have received Oil Spill Awareness Training and SPCC Training. Additional training, specifically addressing labeling of containers for dielectric insulating fluid and containers for Used Oil has been provided for all substation crews.

- Progress Energy has retained several emergency response contractors that are available 24 hours a day/ 7 days a week to respond to large releases. These contractors are equipped to contain, excavate, and provide temporary storage of excavated materials.

- A regular inspection program for substation equipment has been implemented to minimize the frequency and impact from operational leaks. Equipment is wrapped with absorbent padding or absorbent materials are placed below the equipment to prevent releases to the environment. The equipment and absorbents are monitored to prevent releases to the environment until repairs can be made or an equipment outage can be secured to repair the equipment.

Substation Operation and Maintenance Best Management Practices

Preventative maintenance and system upgrades:

- BMPs include modifications to equipment to minimize the risk of spills. A current modification to transformer tapchanger components prevents a complete discharge of oil and a subsequent failure of the transformer.

- During maintenance activities requiring the transfer of dielectric insulating fluid, BMPs to reduce the risk of releases to the environment include: assigning a person responsible for monitoring the transfer; use of portable containment devices positioned under hose connections, filters, and other locations; use of absorbent pads and wraps; covering storm inlets; and having spill control equipment available in case of accidental release.

- An ongoing program of replacing gaskets on equipment is underway to reduce the frequency of leaks. The composition and design of gasket materials are periodically reviewed with the manufacturer to ensure that the most effective gasket materials are in use.

- Regasketing is conducted during a scheduled outage when equipment is taken out of service for an extended period. When gasket replacement cannot be completed due to electricity demand, operational maintenance procedures such as tightening bolts or reducing nitrogen pressure in the equipment is implemented when appropriate.

- A new, contracted epoxy injection repair has been implemented and found to be effective at reducing leaks at certain gaskets.

- Improvements to existing containment structures or new construction of berms, concrete curbs, or containment walls are being completed at all SPCC substation sites.

Site inspections and testing:

- A regular inspection program for substation equipment has been implemented to minimize the frequency and impact from operational leaks.

- Valves and fittings are regularly inspected so that preventative maintenance can be performed on these components before releases to the environment occur. The Substation Rounds Maintenance Order Form has been revised to include a section specifically addressing equipment leaks and other environmental concerns.

- A BMP for testing or performing an applicable waste determination of excavated material prior to disposal has been implemented.

- An environmental self-assessment program has been implemented to obtain input from substation crews on activities at substations that can have impact on the environment.

Progress Energy

SUBSTATION INSPECTION PLAN

Purpose

This Substation Inspection Plan has been prepared in response to the June 17, 2003 Consent Order between Progress Energy Florida and the Florida Department of Environmental Protection. The purpose of the plan is to identify the scope, method, and schedule for conducting inspections of mineral oil discharges at Progress Energy Florida substations. The inspection results will be catalogued and sorted so that substations with mineral oil discharges that could potentially affect human health or the environment can be prioritized for remediation ahead of other substations with mineral oil discharges. The following criteria will be used to prioritize substations for remediation:

- Substation is located adjacent to populated areas
- Substation is located near Waters of the State
- Substation is located near potable water systems or wells
- The number and magnitude of mineral oil discharges onsite

Substation Inspections

The attached Substation Inspection Form (or similar) will be used to conduct each of the inspections at 360+ Progress Energy Substations. The data from the forms will be transferred to a database so that the substations can be prioritized for remediation as described previously.

Reporting

Following completion of the inspections, data tabulation and substation remediation prioritization, a report will be prepared and submitted to FDEP.

Schedule

It is anticipated that the inspections of 360+ substations will take 180 days from plan approval. Data tabulation and report preparation will take an additional 60 days. The substation inspection report will, therefore, be submitted to FDEP within 240 days of plan approval.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030007-EI EXHIBIT NO. Comp. Ex 6
COMPANY/ Progress Energy FL
WITNESS: Patricia Q West - PQW-1+2
DATE: 11-12-03

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 195

[Docket No. RSPA–00–7408; Amdt. No. 195–76]

RIN 2137–AD49

Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With Less Than 500 Miles of Pipelines)

AGENCY: Research and Special Programs Administration (RSPA), U.S. Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: Our regulations for the transportation of hazardous liquids by pipeline require operators with 500 or more miles of regulated pipelines to establish a program for managing the integrity of pipelines that affect high consequence areas. The regulations require continual assessment and evaluation of pipeline integrity through inspection or testing, data integration and analysis, and follow-up remedial, preventive, and mitigative actions. This Final Rule extends those regulations to operators with less than 500 miles of regulated pipelines. We are taking this action because safety recommendations, statutory mandates, and accident analyses indicate that coordinated risk control measures are needed for public safety and environmental protection in addition to compliance with traditional safety standards. Broadening the coverage of the existing regulations will further enhance the protection of high consequence areas against the risk of pipeline failures.

DATES: This Final Rule takes effect February 15, 2002.

FOR FURTHER INFORMATION CONTACT: L. M. Furrow by phone at 202–366–4559, by fax at 202–366–4566, by mail at U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590, or by e-mail at *buck.furrow@rspa.dot.gov*.

SUPPLEMENTARY INFORMATION:

Background

Last year we amended the regulations in 49 CFR part 195 to require each operator who owns or operates 500 or more miles of pipelines subject to part 195 to establish a program for managing the integrity of pipelines that could affect a high consequence area if a leak or rupture occurs (Docket No. RSPA–99–6355; 65 FR 75377; Dec. 1, 2000). High consequence areas include highly populated areas, areas unusually sensitive to environmental damage, and commercially navigable waterways (§ 195.450). Program standards require continual assessment, evaluation, correction, and validation of pipeline integrity (§ 195.452 and appendix C to part 195). The new standards took effect May 29, 2001 (66 FR 9532; Feb. 8, 2001). In addition, in a further rulemaking action (Docket No. RSPA–99–6355), we are revising the repair provisions of § 195.452(h) and clarifying that § 195.452 applies to carbon dioxide pipelines as well as hazardous liquid pipelines.

We did not apply the new program standards to pipelines of operators with less than 500 miles of regulated pipelines primarily because we needed more information about the potential impact of the standards on these operators. We subsequently learned that these operators include, to a large extent, companies with ample resources and capabilities to carry out the standards.

A wide range of persons who submitted comments to Docket No. RSPA–99–6355 supported the need to apply the new program standards to all operators of regulated pipelines that could affect high consequence areas. Based on these comments and the impact information we had collected, we published a Notice of Proposed Rulemaking (NPRM) to extend the program standards to pipelines of operators with less than 500 miles of regulated pipelines (66 FR 15821; March 21, 2001).

The NPRM did not propose any substantive change to the existing program standards. It merely proposed to establish later deadlines for developing programs under § 195.452(b)(1), identifying pipelines under § 195.452(b)(1)(i), completing baseline assessments under § 195.452(d)(1), accepting prior assessments under § 195.452(b)(2), and applying certain time limits on reviewing assessment results under § 195.452(h)(3). We invited interested persons to submit written comments on the proposed rules until May 21, 2001.

Although the NPRM proposed no substantive change to the program standards, in the earlier proceeding (Docket No. RSPA–99–6355), we invited comments until March 31, 2001, on the substance of the standard for remedial action (§ 195.452(h)). As indicated in the NPRM, if § 195.452(h) is changed in that proceeding, the changes will apply to all operators of pipelines to which the program standards apply, including operators covered by the present Final Rule.

Disposition of Comments

This section of the preamble summarizes written comments we received in response to the NPRM. It also describes how we treated those comments in developing the final rules. However, comments related to costs and benefits and the impact of the proposed rules on small entities are addressed in the "Regulatory Analyses and Notices" section of this preamble. If a proposed rule is not mentioned, no significant comments were received on the proposal, and we are adopting the proposed rule as final.

Eight persons submitted comments: a professional organization, the American Society of Safety Engineers (ASSE); a state pipeline safety agency, the Washington Utilities and Transportation Commission (WUTC); a Washington State advisory committee, the Citizens Advisory Committee on Pipeline Safety (CAC); the Small Business Administration (SBA); the Department of Energy (DOE); an engineering firm, Wink, Incorporated (Wink); and two pipeline operators, the Laclede Pipeline Company (Laclede) and the Tosco Corporation (Tosco). ASSE did not comment on specific proposals in the NPRM, but strongly supported our goal of assuring the integrity of pipeline systems. ASSE also said improving pipeline safety would improve the United States' competitive position in the world economy. WUTC, CAC, Tosco, and DOE expressed general support for the NPRM but, along with Wink, suggested changes. DOE also commented on the costs of the proposed rules in their impact on small entities. Laclede opposed the integrity assessment proposal and took issue with our estimate of compliance costs. SBA's comments were limited to the impact of the proposed rules on small entities.

Under proposed §§ 195.452(b)(1) and (b)(1)(i), operators with less than 500 miles of pipelines would have 9 months after the effective date of the final rules to identify all pipeline segments that could affect high consequence areas. They would have 1 year after the effective date to develop a written integrity management program that addresses the risks of those segments. Tosco said the identification of pipeline segments should occur after, not before, integrity management programs are completed, and suggested we allow operators 1 year to complete the identifications. In considering this comment, we noted that operators with 500 or more miles of pipelines have not indicated they expect any significant difficulties in meeting the 9-month identification rule. Tosco's comment

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does not give us reason to believe the 9-month rule might be too burdensome for operators with less than 500 miles of pipelines. While Tosco is correct that operators will need to have relevant program elements in place to guide them in identifying pipeline segments, we believe 9 months is enough time to complete those elements and to carry out the identifications. The additional 3 months the existing rule provides for program development gives operators enough time to complete program elements other than those concerning identification. We do not think this additional time is also needed to identify pipeline segments.

CAC suggested we require operators to seek input from potentially affected communities in identifying high consequence areas. CAC believed the input would help operators identify areas of population at risk and areas of economic importance. Although we recognize community input is valuable in many situations involving pipelines, particularly in site selection and emergency response, we do not feel it is necessary to mandate that operators seek the input CAC envisioned for two reasons. First, the definition of "high consequence area" in § 195.450 covers CAC's concern about the population-at-risk. That definition refers to areas of high or concentrated population that the U.S. Census Bureau has defined and delineated. Operators should be able to identify these areas quite easily using Census Bureau data. If additional information is needed from community records to complete the identifications, the proposed rule would implicitly obligate operators to seek this information, making an explicit requirement unnecessary. Secondly, the NPRM did not propose to require integrity management of pipelines that could affect areas of economic significance other than commercially navigable waterways. These waterways, which operators also can readily identify without community input, arguably are the nation's foremost economic resources potentially at risk from pipeline spills. Other significant economic resources that may be affected by pipelines are less certain, and we feel the present regulations in Part 195 provide those resources adequate protection against the risk of pipeline spills. Similarly, in directing DOT to require additional inspection of certain pipelines, Congress did not include pipelines that affect economic resources other than commercially navigable waterways (49 U.S.C. 60102(f)(2) and 60109). If in the future there is a need to apply the integrity management rules to pipelines affecting other significant economic resources, we will consider whether operators should seek community input in identifying those resources.

Although we did not adopt CAC's recommendations, it is important to note that in a separate proceeding we are considering the need for regulations on better communication of pipeline information by operators to local officials and the public. We have formed a communications work team, consisting of representatives from environmental and public safety organizations, pipeline companies, and government to aid our own hazardous liquid pipeline safety advisory committee in examining communications issues. Notices of meetings of the work group are published in the Federal Register, and minutes of the meetings are posted on this Web site: *http://ops.dot.gov.*

WUTC suggested we require baseline integrity assessments of new pipelines as soon after they are constructed as possible, and for existing pipelines as soon as practicable after the final rules take effect. WUTC stated that early baseline assessment would provide the best basis for comparing subsequent assessment results. The NPRM proposed, in § 195.452(d), that operators with less than 500 miles of pipeline complete baseline assessments within 7 years after the effective date of the final rule, with half the line pipe, selected by risk, assessed within 42 months after the effective date. Alternatively, operators could use as a baseline assessment any qualified integrity assessment completed within the 5 years prior to the effective date. For newly constructed pipelines, hydrostatic testing completed as required by other regulations in Part 195 will fulfill the baseline assessment requirement. Since this testing is normally part of the construction process, it should meet WUTC's objective of early assessment. For existing pipelines, we proposed 7 years to complete baseline assessments because of the volume of assessments, the limited availability of in-line inspection tools, and the time needed to schedule pressure testing to minimize service disruptions. Although we agree with WUTC that earlier baseline assessment would be beneficial, we do not think requiring earlier baseline assessments would be reasonable under present circumstances.

To assure that only qualified persons develop integrity management programs and make program decisions, Wink suggested we require operators to use registered professional engineers with demonstrated technical pipeline expertise and experience. Wink further suggested we require operators to submit their integrity management programs for review by RSPA certified entities. We did not adopt either suggestion because to do so would go beyond the scope of the NPRM. While § 195.452(f)(8) requires operators to use persons qualified to evaluate assessment results and analyze information, the NPRM did not address specific qualifications or program review by certified entities. Based on our experience in other areas of pipeline regulation, we believe operators will use qualified engineers with pipeline experience to assist in developing integrity management programs and recommend critical decisions under the programs. Moreover, persons carrying out regulated assessment and mitigation activities on pipelines are subject to the existing qualification requirements in Subpart G of Part 195. To assure that operators carry out their programs in accordance with the rules, we will use our own engineers and technical specialists to evaluate operators' programs and require changes that may be needed for safety. This type of evaluative process has been satisfactory for other programs and plans required by Part 195. We prefer to continue this approach to assure the quality of integrity management programs rather than establish additional personnel qualifications or a new federal certification program.

Wink asked to what extent operators would have to consider potential terrorist activities in their ongoing assessments of pipeline integrity. Under one of the integrity management program requirements (§ 195.452(e)(1)), operators must schedule integrity assessments based on "all risk factors that reflect the risk conditions on the pipeline." Therefore, if an operator knows or it is reasonable to anticipate that there is a threat to the integrity of the pipeline from terrorist activity, the operator must consider that risk in developing its integrity program. Since the events of September 11, 2001, we are working with DOT, the Department of Energy, the Federal Energy Regulatory Commission, and State agencies, to consider the need for minimum security standards for critical facilities.

Wink postulated that construction permit timing could interfere with an operator's ability to meet remediation deadlines. Section 195.452(h) deals with this potential problem. Under this rule, if justifiable circumstances preclude an operator from meeting specified repair deadlines, the operator may reasonably extend the repair schedule if it

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temporarily reduces operating pressure to a safe level or notifies us of the delay in making a permanent repair.

Finally, Wink suggested we establish a program review process in which operators would meet with our technical specialists to examine whether the program meets applicable requirements. In response to Wink's first comment, we mentioned we will use our own engineers and technical specialists to evaluate operators' programs and require changes that may be needed for safety. We expect this review process will involve meeting with operators' representatives.

Laclede, who operates a 28-mile propane pipeline serving a gas distribution system, believed it would be unreasonable to apply the proposed integrity assessment requirement (§ 195.452(c)) to its pipeline. Laclede said the design of 70 percent of its pipeline cannot accommodate internal inspection tools, and difficulties in de-watering the line after hydrostatic testing would cause control valve and instrument freeze-ups during critical cold weather periods. Laclede suggested we exempt from internal inspection or hydrostatic testing requirements all pipelines directly serving gas distribution systems if the pipeline is cathodically protected and inspected according to our standards or is equipped with emergency flow restricting or shutdown devices. We did not adopt this comment because providing adequate cathodic protection and meeting current inspection requirements cannot assure a pipeline is free from all potentially harmful defects that internal inspection or hydrostatic testing can disclose, such as mechanical damage or fatigue cracks. Also, while emergency flow restricting or shutdown devices are useful in mitigating the consequences of a pipeline rupture, these devices do nothing to prevent ruptures, which is the purpose of periodic internal inspection or hydrostatic testing. Laclede's comment did not fully explain the particular difficulties in de-watering, or drying, its pipeline after hydrostatic testing. Drying pipelines is not an uncommon problem in the industry and not one we believe makes the proposed testing rule unreasonable. Many companies are available to provide expert drying services, using techniques that depend on operating conditions. However, if an operator's circumstances are so unusual that hydrostatic testing would result in unavoidable damage to pipeline facilities and internal inspection is not a viable alternative, the operator may apply for a waiver of the testing requirement as permitted by 49 U.S.C. 60118.

DOE was concerned that construction of new pipelines within the next few years to meet the growing demand for fossil fuels could tax available technical expertise and equipment needed to meet various assessment deadlines in the existing and proposed rules. DOE said available resources could be stretched to a point where meeting the deadlines would not be possible, or at least not possible without significantly increased costs. Therefore, DOE suggested we expand the present provisions for extending deadlines (*e.g.*, § 195.452(j)(4)) to include situations in which meeting a deadline would result in supply disruptions. We agree that by shifting resources away from new construction or shutting down vital pipelines for hydrostatic testing or repair, supply disruptions could occur. However, at this stage we believe the impact of such an eventuality is too speculative to warrant changing the rules to add supply disruption as an acceptable reason for extending deadlines. Also, over the next few years new technologies might become available that would enable acceptable integrity assessments with no effect on supply. If in the future a supply problem appears more likely, the operator involved may petition us for necessary relief or latitude under the rules.

DOE also commented on our plan to identify high consequence areas on it's National Pipeline Mapping System (NPMS) and to make the information available to the public via the Internet. DOE recommended that before implementing this plan, we fully evaluate issues of critical infrastructure protection. Indeed, we designed the NPMS with infrastructure protection issues in mind. For example, to avoid creating a tool for intentional misuse of information with tragic results, critical pipeline components and operating data would not be shown on the NPMS. However, the events of September 11, 2001, have caused even greater concern about the security of critical infrastructure systems. As a result, the NPMS no longer provides open access to pipeline-related data. These data are only available to pipeline operators and local, state, and federal government officials. More information on the availability of data and how operators and officials can access it is on the NPMS home page: http://www.npms.rspa.dot.gov.

Editing Changes

In a further rulemaking action (Docket No. RSPA–99–6355), we are revising § 195.452(h)(3) to eliminate the possibility that periods specified for reviewing integrity assessment results could cause confusion. This change to § 195.452(h)(3) eliminates the need to revise that section to cover operators with less than 500 miles of regulated pipelines. Therefore, this Final Rule does not include the NPRM's proposed change to § 195.452(h)(3).

Because this Final Rule extends the coverage of existing § 195.452 to all operators subject to part 195, there is no need to state in final § 195.452 which operators are subject to § 195.452. Therefore, we edited § 195.452(a) to describe which pipelines are covered by § 195.452 by moving relevant provisions in § 195.452(b)(1) to § 195.452(a). Section 195.452(a) now provides that § 195.452 applies to hazardous liquid and carbon dioxide pipelines that could affect a high consequence area, including pipelines located in a high consequence area unless a risk assessment effectively shows the pipeline could not affect the area.

The NPRM proposed certain compliance dates for covered pipelines that depend on whether the operator of the pipeline owns or operates 500 or more miles of regulated pipelines. Although no one commented on this approach to determining compliance dates, we now recognize the approach could have unintended results. Under the proposed approach, if the miles of regulated pipelines an operator owns or operates changes during the compliance period (through transfer, construction, or abandonment of pipelines), the compliance dates applicable to that operator's covered pipelines could also change. For example, if an operator currently subject to § 195.452 were to reduce its miles of regulated pipelines below 500 during a compliance period for covered pipelines, the operator's covered pipelines would then fall under the later compliance date applicable to operators with less than 500 miles of regulated pipelines. Likewise, covered pipelines of operators who increase their miles of regulated pipelines to 500 or more during a compliance period would become subject to earlier compliance dates. The purpose of the proposed approach to determining compliance dates was merely to establish compliance dates for pipelines covered by the NPRM that are later than the existing compliance dates in § 195.452. We did not intend that the existing or proposed compliance dates change with changes in an operator's regulated pipeline mileage. Rather, we intended to apply the existing and proposed compliance dates to covered pipelines existing on May 29, 2001 (the

effective date of existing § 195.452), depending on whether, on that date, the operator owned or operated 500 or more miles of regulated pipelines.

To clarify the application of compliance dates and to eliminate repetitive wording, final § 195.452(a) divides covered pipelines into three categories. The first category includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to part 195. This category of pipelines is subject to the existing compliance dates in § 195.452, and will remain subject to those dates regardless of how many miles of regulated pipelines the present or future operator of the pipelines owns or operates after May 29, 2001. The second category includes pipelines existing on May 29, 2001, that were owned or operated on that date by an operator who owned or operated less than 500 miles of pipeline subject to part 195. This category of pipelines is subject to the later compliance dates proposed in the NPRM for operators with less than 500 miles of regulated pipelines. Like the first category, the compliance dates applicable to the second category of pipelines do not depend on how many miles of regulated pipelines the present or future operator of the pipelines owns or operates after May 29, 2001. The third category of covered pipelines includes pipelines constructed or converted after May 29, 2001. Because these pipelines are not subject to the existing or proposed compliance dates, we have added appropriate dates to §§ 195.452(b)(1), (b)(2)(i), (d)(1), and (h)(3). The dates in paragraphs (b)(1) and (h)(3) provide compliance periods equivalent to periods allowed for Category 1 or 2 pipelines. In paragraph (b)(2)(i), we set the date as the date the pipeline begins operation, because operators should not need any longer time to identify a new or converted pipeline as a covered pipeline. The date the pipeline begins operation is also the compliance date in paragraph (d)(1), because the hydrostatic test part 195 requires on new and converted pipelines before operation will serve as the baseline assessment.

Advisory Committee Consideration

We presented the NPRM for consideration by the Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) at a meeting in Washington, DC on August 13, 2001 (66 FR 35505; July 5, 2001). The THLPSSC is RSPA's statutory advisory committee for hazardous liquid pipeline safety. The committee has 15 members, representing industry, government, and the public. Each member is qualified to consider the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed pipeline safety standards. The committee voted unanimously to approve the rules proposed in the NPRM and the associated evaluation of costs and benefits. A transcript of the August 13 meeting is available in Docket No. RSPA–98–4470.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures

We consider this Final Rule to be a non-significant regulatory action under section 3(f) of Executive Order 12866 (58 FR 51735; October 4,1993). Therefore, the Office of Management and Budget (OMB) has not received a copy of this rulemaking to review. We do not consider this rulemaking to be significant under DOT regulatory policies and procedures (44 FR 11034; Feb. 26, 1979).

This section of the preamble summarizes the findings of the Regulatory Evaluation we prepared for this Final Rule. A copy of the Regulatory Evaluation is in the docket.

Pipeline spills can adversely affect human health and the environment. However, the magnitude of this impact differs from area to area. There are some areas in which the impact of a spill will be more significant than it would be in others due to concentrations of people who could be affected or to the presence of environmental resources that are unusually sensitive to damage. Because of the potential for dire consequences of pipeline failures in certain areas, these areas merit a higher level of protection. We are promulgating this Final Rule to afford the necessary additional protection to these high consequence areas.

Last year we established 49 CFR 195.450 and 195.452, which are new requirements for additional protection of populated areas, commercially navigable waterways, and areas unusually sensitive to environmental damage from pipeline spills (65 FR 75377; Dec.1, 2000). The new requirements apply to pipeline operators who own or operate 500 or more miles of pipeline. This Final Rule extends the same requirements, with modified compliance deadlines, to the remaining operators of regulated pipelines—those that own or operate less than 500 miles of regulated pipeline.

RSPA and the National Transportation Safety Board (NTSB) have conducted many investigations that have highlighted the importance of protecting the public and environmentally sensitive areas from pipeline failures. NTSB has made several recommendations to ensure the integrity of pipelines near populated and environmentally sensitive areas. These recommendations include requiring periodic testing and inspection to identify corrosion and other damage, establishing criteria to determine appropriate intervals for inspections and tests, determining hazards to public safety from electric resistance welded pipe, and requiring installation of automatic or remotely-operated mainline valves on high-pressure lines to provide for rapid shutdown of failed pipelines.

Congress also directed DOT to undertake additional pipeline safety measures in areas of potentially high consequence. These statutory requirements call for new regulations on identifying pipelines in high density population areas, unusually sensitive environmental areas, and commercially navigable waters. They also call for new regulations on periodic inspections of pipelines in these areas with internal inspection devices, and on emergency flow restricting devices.

This Final Rule requires operators to systematically manage pipeline integrity to reduce the potential for failures that could affect high consequence areas (populated areas, unusually sensitive areas, and commercially navigable waterways). Operators must develop and follow an integrity management program to identify pipeline segments that could affect high consequence areas, and continually assess, through internal inspection, pressure testing, or equivalent alternative technology, the integrity of those segments. The program must also evaluate the segments through comprehensive information analysis, remediate integrity problems, and provide additional protection through preventive and mitigative measures, including the use of emergency flow restricting devices.

Existing §§ 195.450 and 195.452 cover an estimated 86.7 percent of the 157,000 miles of regulated hazardous liquid pipeline in the U.S. This Final Rule covers the remaining 13.3 percent. Of this percentage, we estimate this Final Rule will impact approximately 5,440 miles of pipeline. We estimate the cost to operators to develop the necessary programs at approximately $9.94 million, with an additional annual cost for program upkeep and reporting of $1.32 million. An operator's program begins with a baseline assessment plan and a framework that addresses each

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required program element. The framework indicates how decisions will be made to implement each element. As decisions are made and operators evaluate the effectiveness of the program in protecting high consequence areas, the program will be updated and improved, as needed.

This Final Rule requires a baseline assessment of covered pipeline segments through internal inspection, pressure test, or use of other technology capable of equivalent performance. The baseline assessment must be completed within 7 years after this Final Rule goes into effect. After this baseline assessment, the rule further requires that operators periodically reassess and evaluate pipeline segments to ensure their integrity within a 5-year interval. We estimate the cost of periodic reassessment will generally not occur until the sixth year, unless the baseline assessment indicates significant defects that would require earlier reassessment. Integrating information related to the pipeline's integrity is a key element of the integrity management program. Costs will be incurred in realigning existing data systems to permit integration and in analysis of the integrated data by knowledgeable pipeline safety professionals. The total costs for the information integration requirements in this Final Rule are $6.6 million in the first year and $3.3 million annually thereafter.

This Final Rule requires operators to identify and take preventive or mitigative actions that would enhance public safety or environmental protection, based on a risk analysis of the pipeline segment. One preventive or mitigative action involves installing an emergency flow restricting device on the pipeline segment, if determined necessary. We could not estimate the total cost of installing emergency flow restricting devices because we do not know how many operators will install them. Another action involves evaluating leak detection capability and modifying that capability, if necessary. We do not know how many operators currently have leak detection systems or how many systems will be installed or upgraded as a result of this Final Rule. Therefore, we are unable to estimate the total costs of the leak detection requirements.

As a result of this Final Rule, we expect operators will assess more line pipe than they otherwise would assess. Integrity assessment consists of a baseline assessment, to be conducted within 7 years after the effective date of the final rule, and subsequent reassessment at intervals not to exceed every 5 years. We estimate the cost of additional baseline assessments at approximately $377,000 a year, and the cost of additional reassessments at approximately $531,000 a year. Cost impact will be greater in the sixth and seventh years after the effective date of the final rule due to an overlap between baseline inspection and the initial subsequent inspection. The additional costs in these two years are estimated at $5.26 million.

We cannot easily quantify the benefits of this Final Rule, but we can describe them qualitatively. Issuance of this Final Rule ensures that all operators will perform at least to a baseline safety level and will contribute to an overall higher level of safety and environmental performance nationwide.

The Final Rule will lead to greater uniformity in how risk is evaluated and addressed. It will also provide more clarity in discussions by government, industry and the public about safety and environmental issues, and how the issues can be resolved.

Section 195.452 is written using a performance-based approach. This approach has several advantages. First, it encourages development and use of new technologies. Secondly, it supports operators' development of more formal, structured risk-based programs. Thirdly, it supports continual evaluation of the programs by RSPA and state inspectors. And lastly, it provides greater opportunity for operators to customize their long-term maintenance programs.

Section 195.452 has stimulated the pipeline industry to develop its own consensus standard using a risk-based approach to integrity management. The rule has further fostered development of industry-wide technical standards, such as repair criteria to use following an internal inspection.

The Final Rule encourages a balanced program, addressing the range of prevention and mitigation needs and avoiding reliance on any single tool or overemphasis on any single cause of failure. A balanced program will lead to addressing the most significant risks in populated areas, unusually sensitive environmental areas, and commercially navigable waterways, thus improving industry performance in these areas.

The Final Rule requires a verification process that gives RSPA and state inspectors an opportunity to influence the methods of assessment and the interpretation of results. Government monitoring of the adequacy and implementation of this process should expedite the operators' rates of remedial action and reduce the public's exposure to risk.

A particularly significant benefit of this Final Rule involves the information that operators will gather to support decisions. Two essential elements of the integrity management program are the continual assessment and evaluation of pipeline integrity using inspection and testing technology, and the integration and analysis of all available information about the pipeline. The processes of planning, assessment, and evaluation will provide operators with better data to use in determining a pipeline's condition and the location of potential problems that must be addressed. Also, government inspectors will be able to focus on potential risks and consequences that require greater scrutiny and the need for more intensive preventive and mitigation measures.

The public has expressed concern about the danger pipelines may pose to their neighborhoods. The integrity management process leads to greater accountability to the public for both operators and DOT. This accountability is enhanced through our choice of a map-based approach to defining the areas most in need of additional protection—a visual depiction of pipelines in relation to populated areas, unusually sensitive environmental areas, and commercially navigable waterways. The system integrity requirements will assure the public that operators are continually inspecting and evaluating the threats to pipelines that pass through or close to populated areas.

We have not estimated quantitative benefits for the continual integrity management evaluation required by this Final Rule. We do not believe, however, that requiring this comprehensive process, including the reassessment of pipelines every 5 years, will be an undue burden on operators. We believe the added security this assessment will provide and the generally expedited rate of strengthening the pipeline system in high consequence areas are benefit enough to promulgate these requirements.

Laclede commented that we grossly underestimated implementation costs. Laclede notes that our estimate of the cost for all affected operators is $9.64 million, whereas Laclede expects itself to incur costs in excess of $1 million to modify its pipeline. Laclede's estimated costs are to replace piping that can not now be inspected with internal inspection devices. The rule does not require such pipe replacement, and costs for such replacement therefore were not included in the implementation cost estimate. The rule allows use of hydrostatic testing as an alternative to internal inspection. Laclede's replacement of piping to allow passage of internal inspection devices, if

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undertaken, would be an operational choice based on the company's conclusion that internal inspection would be a better method of assessment than hydrostatic testing. Operators are free to make such operational choices, but they are not required by the rule, and costs associated with pipe replacement are not, therefore, a cost of implementing the rule. We fully considered the costs of hydrostatic testing in the Regulatory Evaluation.

DOE expressed concern that costs associated with shutdown time during assessment or with obtaining permits to conduct repair activities may not have been included in the Regulatory Evaluation. DOE also thought per-mile cost estimates may not be appropriate for operators with only a few miles of pipe. With respect to the impact on small entities, DOE thought the requirements could have an unreasonable impact in some cases.

The values we used to estimate costs for internal inspection and hydrostatic testing were based on detailed studies of both methods that considered all relevant costs. The outcome of those studies are per-mile estimates for conducting assessments. We recognize that costs may be higher for operators that have only a few miles of pipeline, and for whom "fixed" costs of assessment would be amortized over just a few miles. However, we are unable to estimate how many operators may be so affected. Many of the operators subject to this Final Rule are parts of larger companies, as described further in response to Small Business Administration comments, and should not be so affected. We will work with operators who may be unusually impacted, each of whom may request a waiver from particular requirements.

While costs for permitting associated with conducting assessments were included, permitting costs associated with repairs were not estimated. No repair costs were included in the Regulatory Evaluation. This rule does impose time limits on the repair of certain types of defects. Generally, however, repair of conditions that could adversely affect the safe operation of a pipeline is already required by 49 CFR 195.401 and so is not a new requirement in this rule.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), we must consider whether a rulemaking would have a significant impact on a substantial number of small entities. This Final Rule covers only those operators that own or operate less than 500 miles of regulated pipeline. Because of this limitation, only 132 hazardous liquid pipeline operators, covering 13.3 percent of regulated hazardous liquid pipelines, are covered by the Final Rule.

The risks of operating pipelines are similar regardless of the size of the operating company. Accordingly, the need to protect against those risks is also similar, regardless of operator size. We agree with WUTC's comment that "[t]he integrity of the hazardous liquid infrastructure that runs beneath our nation's cities, and crosses our public and private lands, should not be treated differently depending on the amount of pipeline owned or operated by pipeline companies."

We established an artificial cutoff criterion of 500 miles specifically so that we could review further the potential impact and safety needs of smaller operators to see if different treatment was needed. We completed our review and concluded that different treatment was not needed. By this Final Rule, we are establishing the same integrity management requirements for operators with less than 500 miles of pipelines as we established previously for operators with more pipeline mileage. Extending the existing requirements to the remaining operators of regulated pipelines is necessary to ensure the integrity of pipelines which could, if damaged or ruptured, cause significant injury to public safety and the environment.

We preliminarily concluded that there is no disproportionate impact on small businesses, principally because the risks are the same. We examined the companies that operate less than 500 miles of pipelines. A few of these operators are "small businesses" (less than 1500 employees, the Small Business Administration's criterion for defining a small business in the hazardous liquid pipeline industry.) The majority, however, is not. The majority includes larger companies or divisions or subsidiaries of very large national and multi-national companies.

We estimate that 132 operators are potentially subject to the requirements of this Final Rule, because that is the number of operators who paid user fees on less than 500 miles of pipeline in the last fiscal year. This number is a conservative upper bound. Some of these operators are not, in fact, affected by this rulemaking. As noted above, many are divisions or subsidiaries of larger companies. In many cases, the parent companies have other divisions or subsidiaries that operate pipelines and, when all are considered, own or operate more than 500 miles of such pipeline. Those companies, including all their divisions and subsidiaries which may, themselves, operate less than 500 miles of pipeline, are covered by existing § 195.452 and not by this Final Rule. In addition, this Final Rule only covers pipeline segments that could affect a high consequence area. It is possible that some operators, particularly those with only a few miles of pipe, may not operate any segments that could affect such areas. If so, those operators would not be covered by this Final Rule. Nevertheless, we continue to estimate costs on the basis of 132 covered companies, in order to provide a conservative estimate.

SBA thought the NPRM's discussion of the Regulatory Flexibility Act was inadequate. The discussion did not include background and basis information that was in the previous rulemaking applicable to operators with 500 or more miles of regulated pipeline. However, in the present document we have improved our discussion of Regulatory Flexibility Act issues to describe more clearly the basis for concluding that this Final Rule does not disproportionately affect small businesses. SBA's comments are also discussed in detail in the final Regulatory Evaluation, included in the docket.

Therefore, based on the facts available about the anticipated impacts of this rulemaking, I certify, pursuant to section 605 of the Regulatory Flexibility Act (5 U.S.C. 605), that this Final Rule will not have a significant impact on a substantial number of small entities.

Paperwork Reduction Act

This Final Rule contains information collection requirements. As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), we have submitted a copy of the Paperwork Reduction Act Analysis to the OMB for review. The name of the information collection is "Pipeline Integrity Management in High Consequence Areas for Operators with less than 500 miles of pipeline." The purpose of this information collection is designed to require operators of pipelines to develop a program to provide direct integrity testing and evaluation of pipelines in high consequence areas.

No comment submitted in response to the NPRM addressed the information collection requirements.

One hundred and thirty-two operators of hazardous liquid pipelines will be potentially subject to this Final Rule. We estimate that those operators will have to develop integrity management programs taking approximately 2,800 hours per program. Each of the operators will also have to devote 1,000 hours in the first year to integrate data

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into current management information systems.

Additionally, under this Final Rule, operators will have to update their integrity management programs on a continual basis. We estimate updates will take approximately 330 hours per program, annually. An additional 500 hours per operator is estimated for the requirement to annually integrate data into the operator's current management information systems.

Under the Final Rule, operators may use either hydrostatic testing or an internal inspection tool as a method to assess their pipelines. However, operators may use another technology if they can demonstrate it provides an equivalent understanding of the condition of the line pipe as the other two assessment methods. Operators have to provide RSPA 90-days notice (by mail or facsimile) before using the other technology. We believe that few operators will choose this option. If they do choose an alternative technology, notice preparation should take approximately 1 hour. Because we believe few if any operators will elect to use other technologies, the burden was considered minimal and therefore not calculated.

Additionally, the Final Rule allows operators in particular situations to vary from the 5-year continual reassessment interval or repair schedule if they can provide the necessary justification and supporting documentation. Advance notice would have to be provided to RSPA if an operator does so. The advance notification can be in the form of letter or fax. We believe the burden of a letter or fax is minimal and therefore did not add it to the overall burden hours discussed above.

Organizations and individuals desiring to submit comments on the information collection should direct them to: The Office of Management and Budget, Office of Information and Regulatory Affairs, ATTN: RSPA Desk Officer, 727 Jackson Place, NW, Washington, DC 20503. Please provide the docket number of this action. Comments must be sent within 30 days of the publication of this Final Rule.

OMB is specifically interested in the following issues concerning the information collection:

1. Evaluating whether the collection is necessary for the proper performance of the functions of DOT, including whether the information would have a practical use;

2. Evaluating the accuracy of DOT's estimate of the burden of the collection of information, including the validity of assumptions used;

3. Enhancing the quality, usefulness and clarity of the information to be collected; and minimizing the burden of collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology; *e.g.*, permitting electronic submission of responses.

According to the Paperwork Reduction Act of 1995, no persons are required to respond to a collection of information unless a valid OMB control number is displayed. The OMB control number for this information collection is 2137–0605.

Executive Order 13084

This Final Rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13084 ("Consultation and Coordination with Indian Tribal Governments"). Because this proposed rule does not significantly or uniquely affect the communities of the Indian tribal governments and does not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

Executive Order 13132

This Final Rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13132 ("Federalism"). This Final Rule does not adopt any regulation that: (1) Has substantial direct effects on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government; (2) imposes substantial direct compliance costs on state and local governments; or (3) preempts state law. Therefore, the consultation and funding requirements of Executive Order 13132 (64 FR 43255, Aug. 10, 1999) do not apply. In a public meeting we held on November 18–19, 1999, we invited the National Association of Pipeline Safety Representatives (NAPSR), which includes State pipeline safety regulators, to participate in a general discussion on pipeline integrity. Again in January, and February 2000, we held conference calls with NAPSR, to receive its input before proposing an integrity management rule.

Impact on Business Processes and Computer Systems

We do not want to impose new requirements that would mandate business process changes when the resources necessary to implement those requirements would otherwise be applied to "Y2K" or related computer problems. This Final Rule does not mandate business process changes or require modifications to computer systems. Because the final rules will not affect the ability of organizations to respond to those problems, we are not delaying the effectiveness of the requirements.

Unfunded Mandates Reform Act of 1995

This Final Rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of $100 million or more to either state, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the NPRM.

National Environmental Policy Act

We have analyzed the Final Rule in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. 4332), the Council on Environmental Quality regulations (40 CFR parts 1500–1508), and DOT Order 5610.1D. We have determined that this action will not significantly affect the quality of the human environment.

The Environmental Assessment (available in the Docket) determined that the combined impacts of the initial baseline assessment (pressure testing or internal inspection), the subsequent periodic assessments, and additional preventive and mitigative measures that may be implemented to protect high consequence areas will result in positive environmental impacts. The number of incidents and the environmental damage from failures in and near high consequence areas are likely to be reduced. However, from a national perspective, the impact is not expected to be significant for the pipeline operators covered by the Final Rule. The following discussion summarizes the analysis provided in the Environmental Assessment.

Many operators covered by the Final Rule (those operating less than 500 miles of regulated pipeline) already have internal inspection and pressure testing programs that cover most, if not all, of their pipeline systems. These operators typically place a high priority on the pipeline's proximity to populated areas, commercially navigable waterways, and environmental resources when making decisions about where and when to inspect and test pipelines. As a result, some high consequence areas have already been recently assessed, and a large fraction of remaining locations would probably have been assessed in the next several years without the Final Rule. The most tangible impact will be to ensure

Exhibit ____ (PQW-1)
Progress Energy Florida
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assessments are performed for those line segments that could affect a high consequence area that are not currently being internally inspected or pressure tested, and ensuring that integrity is maintained through an integrity management program that requires periodic assessments in these locations. Because hazardous liquid pipeline failure rates are low, and because the total pipeline mileage operated by operators with less than 500 miles of pipeline that could affect high consequence areas is small, the Final Rule has only a small effect on the likelihood of pipeline failure in these locations.

The Final Rule will result in more frequent integrity assessments of line segments that could affect high consequence areas than most operators are currently conducting (due to the 5-year interval required for periodic assessment). However, if the operator identifies and repairs significant problems discovered during the baseline inspection, and has in place solid risk controls to prevent corrosion and other threats, as they must, the benefits of assessing every 5 years versus the longer intervals operators more typically employ are not expected to be significant.

The Final Rule requires operators to conduct an integrated evaluation of all potential threats to pipeline integrity, and to consider and take preventive or mitigative risk control measures to provide enhanced protection. If there is a vulnerability to a particular failure cause, like third-party damage, these evaluations should identify additional risk controls to address these threats. Some operators covered by the Final Rule already perform integrity evaluations or formal risk assessments that consider the environmental sensitivity and impacts on population. These evaluations have already led to additional risk controls beyond existing requirements to improve protection for these locations. For these operators, it is expected that additional risk controls will be limited and customized to site-specific conditions that the operator may not have previously recognized.

Finally, an important, although less tangible, benefit of the Final Rule will be to establish requirements for operator integrity management programs that assure a more comprehensive and integrated evaluation of pipeline system integrity in high consequence areas. In effect, this will codify and bring an appropriate level of uniformity to the integrity management programs some operators are currently implementing. It will also require operators who have limited, or no, integrity management programs to raise their level of performance.

We expect this Final Rule to provide a more consistent, and overall, a higher level of protection for high consequence areas across the nation. Even though there is a benefit, we have concluded that it is not significant, and, therefore, have issued a finding of no significant impact.

Executive Order 13211

This rulemaking is not a "Significant energy action" under Executive Order 13211. It is not a significant regulatory action under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, this rulemaking has not been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

List of Subjects in 49 CFR Part 195

Carbon dioxide, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, we are amending 49 CFR part 195 as follows:

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

1. The authority citation for part 195 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60118; and 49 CFR 1.53.

Subpart F—Operation and Maintenance

2. In § 195.452, paragraphs (a), (b), (d) heading, (d)(1), and (d)(2) are revised and paragraph (d) introductory text is added to read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

(a) *Which pipelines are covered by this section?* This section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. (Appendix C of this part provides guidance on determining if a pipeline could affect a high consequence area.) Covered pipelines are categorized as follows:

(1) Category 1 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to this part.

(2) Category 2 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline subject to this part.

(3) Category 3 includes pipelines constructed or converted after May 29, 2001.

(b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must:

(1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1	March 31, 2002.
Category 2	February 18, 2003.
Category 3	1 year after the date the pipeline begins operation.

(2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1	December 31, 2001.
Category 2	November 18, 2002.
Category 3	Date the pipeline begins operation.

(3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.

(4) Include in the program a framework that—

(i) Addresses each element of the integrity management program under paragraph (f) of this section, including continual integrity assessment and evaluation under paragraph (j) of this section; and

(ii) Initially indicates how decisions will be made to implement each element.

(5) Implement and follow the program.

(6) Follow recognized industry practices in carrying out this section, unless—

(i) This section specifies otherwise; or

(ii) The operator demonstrates that an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection.

* * * * *

(d) *When must operators complete baseline assessments?* Operators must complete baseline assessments as follows:

(1) *Time periods.* Complete assessments before the following deadlines:

If the pipeline is:	Then complete baseline assessments not later than the following date according to a schedule that prioritizes assessments:	And assess at least 50 percent of the line pipe on an expedited basis, beginning with the highest risk pipe, not later than:
Category 1	March 31, 2008	September 30, 2004.
Category 2	February 17, 2009	August 16, 2005.
Category 3	Date the pipeline begins operation	Not applicable.

(2) *Prior assessment.* To satisfy the requirements of paragraph (c)(1)(i) of this section for pipelines in the first column of the following table, operators may use integrity assessments conducted after the date in the second column, if the integrity assessment method complies with this section. However, if an operator uses this prior assessment as its baseline assessment, *the operator must reassess the line pipe* according to paragraph (j)(3) of this section. The table follows:

Pipeline	Date
Category 1	January 1, 1996.
Category 2	December 18, 2006.

* * * * *

Issued in Washington, DC, on January 8, 2002.

Ellen G. Engleman,

Administrator.

[*FR Doc. 02–858 Filed 1–15–02; 8:45 am*]

BILLING CODE 4910–60–P

2. Bulk product piping that is in contact with the soil shall have secondary containment.

3. Remote fill piping that is in contact with the soil shall have secondary containment.

4. The following integral piping systems are exempt from the requirements for secondary containment:

a. Integral piping that is in contact with the soil, and that is connected to storage tanks containing high viscosity regulated substances; and

b. Vertical fill pipes equipped with a drop tube.

Specific Authority 376.303 FS.
Law Implemented 376.303 FS.
History--New 12-10-90, Amended 5-4-92, Formerly 17-761.500, Amended 9-30-96, 7-13-98.

62-761.510 Performance Standards for Category-A and Category-B Storage Tank Systems.

(1) General. This section provides deadlines for Category-A and Category-B storage tank systems to meet the standards for Category-C storage tank systems in accordance with Rule 62-761.500, F.A.C.

(a) Installation:

1. Installation shall be completed by the deadlines specified in Table UST and Table AST. However, if installation or upgrade activities are initiated before the deadlines, work can continue after the deadlines, provided that all work is completed within 90 days of:

a. Contract execution; or

b. Receipt of construction approval or permits.

2. Installation is considered to have begun if:

a. All federal, state, and local approvals or permits have been obtained or applied for to begin physical construction for installation of the system; or

b. Contractual obligations have been made for installation of the system which cannot be canceled or modified without substantial economic loss, provided that such obligations are pursued diligently in good faith to achieve the requirements of this rule.

(b) By December 31, 1998:

1. All pressurized small diameter piping systems connected to dispensers shall have shear valves or emergency shutoff valves installed in accordance with Rule 62-761.500(4)(c), F.A.C.

2. Cathodic protection test stations shall be installed in accordance with Rule 62-761.500(1)(f)1. and (2)(b)2. F.A.C., for cathodically protected UST or AST systems without test stations.

3. Fillboxes shall be color coded in accordance with Rule 62-761.500(2)(d)1., F.A.C.

4. ASTs that have been reinstalled as USTs, and USTs that have been reinstalled as ASTs, shall meet the requirements of Rule 62-761.500, F.A.C.

(c) After July 13, 1998, a closure assessment shall be performed in accordance with Rule 62-761.800(4), F.A.C., before the installation of dispenser liners, piping sumps, or secondary containment of tanks and integral piping.

(d) Valves meeting the requirements of Section 2-1.7 of NFPA 30A, shall be installed by January 13, 1999 on any storage tank system located at an elevation that produces a gravity head on the dispenser or on small diameter piping.

(e) Small diameter piping transporting regulated substances over surface waters of the state shall have secondary containment by December 31, 2004.

(2) Underground storage tank systems.

(a) UST Category-A single-walled tanks or underground single-walled piping shall be considered to be protected from corrosion if the tank or piping was constructed with corrosion resistant materials, initially installed with cathodic protection, or had cathodic protection or internal lining installed before June 30, 1992.

(b) UST Category-B systems.

1. All tanks containing pollutants, installed or constructed at a facility after June 30, 1992, shall have secondary containment.

2. All tanks containing hazardous substances, installed or constructed at a facility after January 1, 1991, shall have secondary containment.

(c) Small diameter integral piping in contact with the soil that is connected to UST systems shall have secondary containment if installed after December 10, 1990.

(d) By December 31 of the appropriate year shown in Table UST below, all storage tank systems shall meet the performance standards of Rule 62-761.500, F.A.C., or be permanently closed in accordance with Rule 62-761.800(3), F.A.C.

TABLE UST

Year Tank or Integral Piping Installed	1989	1992	1995	1998	2004	2009
+Before 1970	O	B		ACFL	D	E
+1970 - 1975		SBL		ACF	D	E
+l976 - 1980		B	SL	ACF	D	E
+1981 - 09/01/84		B		ACFL	D	E
+09/02/84 – 06/30/92		B		ACFL	D	E
+Other*		B		ACFL	D	E

Key to Table UST

* = All systems with a capacity between 110 gallons and 550 gallons, all marine fueling facilities as defined in Section 376.031, F.S., and those systems of greater than 550 gallon capacity that use less than 1,000 gallons per month or 10,000 gallons per year.

A =

(1) Small diameter piping that was protected from corrosion by June 30, 1992, shall have:

(a) For pressurized piping, line leak detectors with automatic shutoff, or flow restriction in accordance with Rule 62-761.640(3)(d), F.A.C.; or

(b) For suction integral piping:

1. Secondary containment in accordance with Rule 62-761.500(1)(e), F.A.C.;

2. A single check valve installed in accordance with Rule 62-761.610(4)(a)3., F.A.C.;

3. An annual line tightness test in accordance with Rule 62-761.610(4)(a)1., F.A.C.; or

4. External monthly monitoring or release detection in accordance with Rule 62-761.610(4)(a)1.b., F.A.C.

(2) Bulk product piping in contact with soil shall be upgraded with secondary containment unless the piping is:

(a) Constructed of corrosion resistant materials or upgraded with cathodic protection; and

(b) Tested on an annual basis in accordance with API RP 1110, ASME B31.4, or an equivalent method approved by the Department in accordance with Rule 62-761.850, F.A.C.

B = Vehicular fuel petroleum storage tank systems shall be upgraded with spill containment.

C = Secondary containment in accordance with Rule 62-761.500(1)(e), F.A.C., shall be required for the following:

(1) Concrete storage tanks;

(2) Hazardous substance storage tank systems; and

(3) For pollutant storage tank systems, the storage tank or small diameter piping not protected from corrosion by June 30, 1992.

D = (1) Secondary containment shall be installed for small diameter piping extending over surface waters.

(2) Secondary containment for remote fill-pipes associated with Category-A and Category-B systems.

E = Pollutant storage tanks and small diameter piping protected from corrosion on or before June 30, 1992, and all manifolded piping, shall be upgraded with secondary containment.

F =

(1) Storage tank systems, excluding vehicular fuel petroleum storage tank systems, shall be upgraded with spill containment, dispenser liners (as applicable), and overfill protection.

(2) Unless contained within secondary containment, swing-joints and flex-connectors that are not protected from corrosion shall be protected from corrosion. Facilities that have pressurized small diameter piping and that have not met the foregoing standard on or before July 13, 1998 shall protect the submersible turbine pump from corrosion or provide corrosion protection for the submersible turbine pump if the pump is not installed within secondary containment. Corrosion protection is not required for the submersible turbine pump riser.

L =

(1) Category-A USTs and their integral piping systems that contain vehicular fuel, and that are not protected from corrosion, shall have secondary containment, or be upgraded with secondary containment in accordance with Rule 62-761.500, F.A.C.

(2) Dispenser liners and overfill protection equipment shall be installed at UST Category-A systems containing vehicular fuel.

O = UST Category-A vehicular fuel storage tank systems subject to Chapter 17-61, F.A.C.,(1984), shall be retrofitted for corrosion protection.

S = Secondary containment for storage tanks and integral piping not protected from corrosion.

(3) Aboveground storage tank systems.

(a) All storage tank systems with tanks having capacities greater than 550 gallons that contain vehicular fuel and that were subject to Chapter 17-61, F.A.C., shall have met the requirements of such chapter by January 1, 1990.

(b) AST Category-B tanks, with the exception of tanks exempt under Rule 62-761.500(3)(c)1., F.A.C., installed or constructed at a facility after March 12, 1991, shall have secondary containment for the tank.

(c) Integral piping that is in contact with the soil and that is connected to AST systems shall have secondary containment if installed after March 12, 1991. For integral piping that is exempt under Rule 62-761.500(4)(e)4., F.A.C., it is not required to install secondary containment.

(d) By January 1 of the appropriate year shown in Table AST below, unless specified otherwise, all AST Category-A and Category-B storage tank systems shall meet the following requirements or be permanently closed in accordance with Rule 62-761.800(3), F.A.C.

TABLE AST

Year Tank or Integral Piping Installed	1993	2000	2005	2010
+Before July 13, 1998	P	TVX	W	U

Key to Table AST

P = With the exception of high viscosity bulk product piping, bulk product piping in contact with soil and not in secondary containment shall be tested in accordance with API RP 1110, ASME B31.4, or an equivalent method approved by the Department in accordance with Rule 62-761.850, F.A.C. Such testing shall be performed annually thereafter.

T =

(1) With the exception of siting and material construction standards, Category-A and Category-B systems shall meet the performance standards of Rule 62-761.500, F.A.C. In addition:

(a) Storage tank system construction standards that include cathodic protection remain applicable; and

(b) Storage tanks where the entire bottom of the tank is in contact with concrete do not have to seal the concrete beneath the tank until such time that the tank bottom is

replaced. However, concrete secondary containment systems designed in accordance with Rule 62-761.500(1)(e)3., F.A.C., do not have to be sealed.

(2) Category-A bulk product piping in contact with the soil shall be upgraded with secondary containment, unless:

(a) A structural evaluation is performed in accordance with API 570, as specified in "U" (2)(b), of Table AST, and results of the structural evaluation indicate that the bulk product piping has remaining useful life; or

(b) The integral piping conveys high viscosity regulated substances, that are exempt from secondary containment in accordance with Rule 62-761.500(4)(e) 4., F.A.C.; or

(c) The integral piping is protected from corrosion and is tested annually in accordance with ASME B31.4, API 1110, or an equivalent method approved by the Department in accordance with Rule 62-761.850, F.A.C. This piping shall have secondary containment by January 1, 2010, in accordance with "U" of Table AST.

(3) Initial internal and external inspections, examinations, and tests for each tank shall be performed in accordance with API Standard 653, and an appropriate reinspection interval for each tank shall be established in accordance with API Standard 653. If any deficiency is discovered during the inspections, the person performing the evaluation of the tank in accordance with API 653 must verify that the tank is ready for service before the storage tank is put back into service. This verification must be documented in the internal inspection records. Future tests for each tank shall be performed in accordance with the inspection interval established in accordance with API 653 (1996). Baseline inspections already conducted according to the API Standard 653 (1991) will be accepted.

(4) As an alternative to installing secondary containment underneath an AST Category-A or Category-B storage tank, the interior bottom of the tank and at least 18 inches up the sides may be internally lined in accordance with API RP 652. Secondary containment must nonetheless be installed in the dike field area and be continuously bonded to the perimeter of the tank foundation.

U =

(1) All internally lined single bottom storage tanks, with the exception of tanks exempt under Rule 62-761.500(3)(c)1., F.A.C., shall be upgraded with secondary containment.

(2) All AST Category-A bulk product piping in contact with the soil , except for piping exempt from secondary containment requirements under Rule 62-761.500(4)(e)4. F.A.C., shall be:

(a) Upgraded with secondary containment in accordance with Rule 62-761.500(1)(e), F.A.C.; or

(b) Instead of being upgraded with secondary containment, be evaluated for structural integrity by:

1. Establishing and maintaining the piping inspection intervals in accordance with API 570, Section 4-2, by January 1, 2000;

2. Determining the remaining life of the system in accordance with API 570, Section 5.0, by January 1, 2000. If the determination indicates that the piping:

a. Must be repaired, then the piping shall be repaired within three months of the determination in accordance with API 570 and Rule 62-761.700, F.A.C.;

b. Is leaking, then the piping must be immediately taken out of operation. If the piping cannot be repaired, it must be closed or upgraded with secondary containment within one year of the determination;

c. Is not leaking, but has corroded to a point where it no longer has structural integrity, then the piping shall be closed, or upgraded with secondary containment by January 1, 2000; or

d. Has remaining useful life, then the piping shall be closed or upgraded with secondary containment when the API 570 inspection and remaining life determination data indicates that closure or replacement is necessary.

3. Providing a certification by a professional engineer registered in the State of Florida that the evaluation meets the above criteria.

V =

(1) Secondary containment for cut and cover or concrete storage tanks.

(2) Spill containment in accordance with Rule 62-761.500(1)(c), F.A.C.

(3) Dispenser liners for shop-fabricated tanks in accordance with Rule 62-761.500(3)(e), F.A.C.

(4) Secondary containment in accordance with Rule 62-761.500(1)(e) and (3)(c), F.A.C., for dike field areas of facilities with shop-fabricated tanks having dike field area secondary containment that is constructed of concrete or installed with synthetic liners not meeting these requirements.

W =

(1) Secondary containment in accordance with Rule 62-761.500(1)(e) and (3)(c), F.A.C., for dike field areas of facilities with field-erected tanks having dike field area secondary containment that is constructed of concrete or installed with synthetic liners not meeting these requirements.

(2) Secondary containment for small diameter piping extending over surface waters.

(3) Secondary containment for small diameter petroleum contact water piping in contact with the soil.

X = Deadline to determine integrity of single wall bulk product piping with an API 570 structural integrity evaluation in accordance with the option for Category-A systems in "U" of Table AST.

Specific Authority 376.303 FS. Law Implemented 376.303-376.3072 FS. History--New 12-10-90, Amended 5-4-92, Formerly 17-761.510, Amended 9-30-96, 07-13-98.

EXHIBIT NO._____
DOCKET NO. 030007-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 2002 - DECEMBER 2002

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030007-EI EXHIBIT NO. 7 Comp. Ex.
COMPANY/ TECO
WITNESS. Howard T. Bryant-HTB 1,2+3
DATE: 11-12-03

DOCUMENT NUMBER-DATE
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FPSC-COMMISSION CLERK

EXHIBIT NO._____
DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)

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ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2002 THROUGH DECEMBER 2002

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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 2002 to December 2002
(in Dollars)

Line		Period Amount
1	End of Period Actual True-Up for the Period January 2002 to December 2002 (Form 42-2A, Lines 5 + 6 +10)	$3,000,695
2	Estimated/Actual True-Up Amount Approved for the Period January 2002 to December 2002 (Order No. PSC-02-1735-FOF-EI)	3,457,263
3	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2004 to December 2004 (Line 1 - 2)	($456,568)

EXHIBIT NO. _____
DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-1)
DOCUMENT NO. 1
PAGE 1 OF 1
FORM 42-1A
FILED: APRIL 1, 2003

Form 42 - 2A

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual True-Up Amount for the Period
January 2002 to December 2002

Current Period True-Up Amount
(in Dollars)

Line	Actual Jan-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	End of Period Total
1. ECRC Revenues (net of Revenue Taxes)	$2,240,715	$1,956,176	$1,922,722	$2,144,060	$2,510,133	$2,524,303	$2,518,676	$2,585,044	$2,596,786	$2,583,385	$2,182,754	$2,077,013	$27,841,767
2. True-Up Provision	59,271	59,271	59,271	59,271	59,271	59,271	59,271	59,271	59,271	59,271	59,271	59,272	711,253
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	2,299,986	2,015,447	1,981,993	2,203,331	2,569,404	2,583,574	2,577,947	2,644,315	2,656,057	2,642,656	2,242,025	2,136,285	28,553,020
4. Jurisdictional ECRC Costs													
a. O & M Activities (Form 42-5A, Line 9)	695,236	252,099	241,157	337,158	581,800	345,239	731,857	380,286	529,926	689,975	386,512	833,808	6,005,053
b. Capital Investment Projects (Form 42-7A, Line 9)	1,630,730	1,663,573	1,638,175	1,620,003	1,625,478	1,626,086	1,621,043	1,616,043	1,611,047	1,613,208	1,640,441	1,654,125	19,559,952
c. Total Jurisdictional ECRC Costs	2,325,966	1,915,672	1,879,332	1,957,161	2,207,278	1,971,325	2,352,900	1,996,329	2,140,973	2,303,183	2,026,953	2,487,933	25,565,005
5. Over/Under Recovery (Line 3 - Line 4c)	(25,980)	99,775	102,661	246,170	362,126	612,249	225,047	647,986	515,084	339,473	215,072	(351,648)	2,988,015
6. Interest Provision (Form 42-3A, Line 10)	(492)	(522)	(465)	(295)	67	696	1,208	1,733	2,517	2,991	2,863	2,379	12,680
7. Beginning Balance True-Up & Interest Provision	711,253	625,510	665,492	708,417	895,021	1,197,943	1,751,617	1,918,601	2,509,049	2,967,379	3,250,572	3,409,236	711,253
a. Deferred True-Up from January to December 2001 (Order No. PSC-02-1735-FOF-EI)	(1,001,138)	(1,001,138)	(1,001,138)	(1,001,138)	(1,001,138)	(1,001,138)	(1,001,138)	(1,001,138)	(1,001,138)	(1,001,138)	(1,001,138)	(1,001,138)	(1,001,138)
8. True-Up Collected/(Refunded) (see Line 2)	(59,271)	(59,271)	(59,271)	(59,271)	(59,271)	(59,271)	(59,271)	(59,271)	(59,271)	(59,271)	(59,271)	(59,272)	(711,253)
9. End of Period Total True-Up (Lines 5 + 6 + 7 +7a + 8)	(375,628)	(335,646)	(292,721)	(106,117)	196,805	750,479	917,463	1,507,911	1,966,241	2,249,434	2,408,098	1,999,557	1,999,557
10. Adjustment to Period True-Up Including Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
11. End of Period Total Net True-Up (Lines 9 + 10)	($375,628)	($335,646)	($292,721)	($106,117)	$196,805	$750,479	$917,463	$1,507,911	$1,966,241	$2,249,434	$2,408,098	$1,999,557	$1,999,557

EXHIBIT NO. _____
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FORM 42-2A
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Form 42 - 3A

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual True-Up Amount for the Period
January 2002 to December 2002

Interest Provision
(in Dollars)

Line	Actual Jan-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	End of Period Total
1. Beginning Balance True-Up Amount (Form 42-2A, Line 7 +7a + 10)	($289,885)	($375,628)	($335,646)	($292,721)	($106,117)	$196,805	$750,479	$917,463	$1,507,911	$1,966,241	$2,249,434	$2,408,098	
2. Ending True-Up Amount Before Interest	(375,136)	(335,124)	(292,256)	(105,822)	196,738	749,783	916,255	1,506,178	1,963,724	2,246,443	2,405,235	1,997,178	
3. Total of Beginning & Ending True-Up (Lines 1 & 2)	(665,021)	(710,752)	(627,902)	(398,543)	90,621	946,588	1,666,734	2,423,641	3,471,635	4,212,684	4,654,669	4,405,276	
4. Average True-Up Amount (Line 3 x 1/2)	(332,511)	(355,376)	(313,951)	(199,272)	45,311	473,294	833,367	1,211,821	1,735,818	2,106,342	2,327,335	2,202,638	
5. Interest Rate (First Day of Reporting Business Month)	1.78%	1.77%	1.75%	1.80%	1.75%	1.77%	1.75%	1.73%	1.71%	1.76%	1.65%	1.30%	
6. Interest Rate (First Day of Subsequent Business Month)	1.77%	1.75%	1.80%	1.75%	1.77%	1.75%	1.73%	1.71%	1.76%	1.65%	1.30%	1.29%	
7. Total of Beginning & Ending Interest Rates (Lines 5 & 6)	3.55%	3.52%	3.55%	3.55%	3.52%	3.52%	3.48%	3.44%	3.47%	3.41%	2.95%	2.59%	
8. Average Interest Rate (Line 7 x 1/2)	1.775%	1.760%	1.775%	1.775%	1.760%	1.760%	1.740%	1.720%	1.735%	1.705%	1.475%	1.295%	
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.148%	0.147%	0.148%	0.148%	0.147%	0.147%	0.145%	0.143%	0.145%	0.142%	0.123%	0.108%	
10. Interest Provision for the Month (Line 4 x Line 9)	($492)	($522)	($465)	($295)	$67	$696	$1,208	$1,733	$2,517	$2,991	$2,863	$2,379	$12,680

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Form 42 - 4A

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
January 2002 to December 2002

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 Investment Projects				
	1a Big Bend Unit 3 Flue Gas Desulfurization Integration	$1,356,402	$1,703,106	($346,704)	-20.4%
	1b Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	1c SO_2 Emissions Allowances	(177,547)	(91,752)	(85,795)	-93.5%
	1d Big Bend Units 1 & 2 FGD	3,747,550	3,440,488	307,062	8.9%
	1e Big Bend FGD Optimization and Utilization	545,489	506,665	38,824	7.7%
	1f Big Bend PM Minimization and Monitoring	616,267	601,989	14,278	2.4%
	1g Big Bend NO_x Emissions Reduction	0	0	0	NA
	1h NPDES Annual Surveillance Fees	43,700	52,133	(8,433)	-16.2%
	1i Gannon Thermal Discharge Study	49,429	43,354	6,075	14.0%
	2. Total Investment Projects - Recoverable Costs	$6,181,290	$6,255,983	($74,693)	-1.2%
	3. Recoverable Costs Allocated to Energy	$6,088,161	$6,160,496	($72,335)	-1.2%
	4. Recoverable Costs Allocated to Demand	$93,129	$95,487	($2,358)	-2.5%

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-02-1735-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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TAMPA ELECTRIC COMPANY
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Form 42 - 5A

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
January 2002 to December 2002

O&M Activities
(in Dollars)

Line	Actual Jan-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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	$180,223	$107,745	$15,760	$8,776	$126,284	$85,105	($8,818)	$30,790	$195,889	$211,724	$146,174	$256,750	$1,356,402		$1,356,402
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	21,599	12,048	8,186	17,960	(39,113)	(10,248)	(18,584)	(15,236)	(20,474)	(21,055)	(21,730)	(90,900)	(177,547)		(177,547)
1d Big Bend Units 1 & 2 FGD	459,060	116,121	177,703	304,003	473,445	278,176	280,953	216,651	287,598	230,447	258,721	664,672	3,747,550		3,747,550
1e Big Bend FGD Optimization and Utilization	0	0	0	(1,179)	0	0	396,707	149,077	0	0	0	884	545,489		545,489
1f Big Bend PM Minimization and Monitoring	5,064	18,577	45,431	20,014	39,798	2,216	103,492	5,156	76,160	270,971	11,347	18,041	616,267		616,267
1g Big Bend NO_x Emissions Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0		0
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	0	0	0	0	0	0	0	6,261	9,093	24,421	2,368	7,286	49,429	49,429	
2. Total of O&M Activities	709,646	254,491	247,080	349,574	600,414	355,249	753,750	392,699	548,266	716,508	396,880	856,733	6,181,290	$93,129	$6,088,161
3. Recoverable Costs Allocated to Energy	665,946	254,491	247,080	349,574	600,414	355,249	753,750	386,438	539,173	692,087	394,512	849,447	6,088,161		
4. Recoverable Costs Allocated to Demand	43,700	0	0	0	0	0	0	6,261	9,093	24,421	2,368	7,286	93,129		
5. Retail Energy Jurisdictional Factor	0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077			
6. Retail Demand Jurisdictional Factor	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189			
7. Jurisdictional Energy Recoverable Costs (A)	655,079	252,099	241,157	337,158	581,800	345,239	731,857	374,533	521,570	667,534	384,336	827,113	5,919,475		
8. Jurisdictional Demand Recoverable Costs (B)	40,157	0	0	0	0	0	0	5,753	8,356	22,441	2,176	6,695	85,578		
9. Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$695,236	$252,099	$241,157	$337,158	$581,800	$345,239	$731,857	$380,286	$529,926	$689,975	$386,512	$833,808	$6,005,053		

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

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
January 2002 to December 2002

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	$1,003,292	$1,003,292	$0	0.0%
1b	Big Bend Units 1 & 2 Flue Gas Conditioning	599,403	599,403	0	0.0%
1c	Big Bend Unit 4 Continuous Emissions Monitors	103,331	103,331	0	0.0%
1d	Gannon Ignition Oil Tank	109,091	109,091	0	0.0%
1e	Big Bend Fuel Oil Tank #1 Upgrade	66,218	66,218	0	0.0%
1f	Big Bend Fuel Oil Tank #2 Upgrade	108,914	108,914	0	0.0%
1g	Phillips Upgrade Tank #1 for FDEP	8,100	8,100	0	0.0%
1h	Phillips Upgrade Tank #4 for FDEP	12,759	12,759	0	0.0%
1i	Gannon Unit 5 Classifier Replacement	309,071	309,071	0	0.0%
1j	Gannon Unit 6 Classifier Replacement	357,380	357,380	0	0.0%
1k	Big Bend Unit 1 Classifier Replacement	180,357	180,357	0	0.0%
1l	Big Bend Unit 2 Classifier Replacement	131,697	131,697	0	0.0%
1m	Gannon Coal Crusher (NO_x Control)	1,310,633	1,310,633	0	0.0%
1n	Big Bend Units 1 & 2 FGD	12,282,575	12,282,575	0	0.0%
1o	Big Bend Section 114 Mercury Testing Platform	15,854	15,854	0	0.0%
1p	Big Bend FGD Optimization and Utilization	3,072,557	3,075,564	(3,007)	-0.1%
1q	Big Bend PM Minimization and Monitoring	199,678	214,441	(14,763)	-6.9%
1r	Big Bend NO_x Emissions Reduction	245,256	244,972	284	0.1%
1s	Polk NO_x Emissions Reduction	4,280	0	4,280	NA
2.	Total Investment Projects - Recoverable Costs	$20,120,446	$20,133,652	($13,206)	-0.1%
3.	Recoverable Costs Allocated to Energy	$19,815,364	$19,828,570	($13,206)	-0.1%
4.	Recoverable Costs Allocated to Demand	$305,082	$305,082	$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-02-1735-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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TAMPA ELECTRIC COMPANY
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Form 42 - 7A

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
January 2002 to December 2002

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		Actual Jan-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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	$84,634	$84,447	$84,261	$84,074	$83,887	$83,701	$83,514	$83,328	$83,142	$82,954	$82,768	$82,582	$1,003,292		$1,003,292
1b	Big Bend Units 1 & 2 Flue Gas Conditioning	50,711	50,572	50,434	50,296	50,158	50,019	49,881	49,743	49,605	49,466	49,328	49,190	599,403		599,403
1c	Big Bend Unit 4 Continuous Emissions Monitors	8,715	8,696	8,677	8,658	8,639	8,621	8,601	8,583	8,564	8,544	8,526	8,507	103,331		103,331
1d	Gannon Ignition Oil Tank	9,189	9,112	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	109,091	$109,091	
1e	Big Bend Fuel Oil Tank #1 Upgrade	5,580	5,569	5,558	5,546	5,535	5,524	5,513	5,501	5,490	5,479	5,467	5,456	66,218	66,218	
1f	Big Bend Fuel Oil Tank #2 Upgrade	9,178	9,160	9,141	9,123	9,104	9,086	9,067	9,049	9,029	9,011	8,992	8,974	108,914	108,914	
1g	Phillips Upgrade Tank #1 for FDEP	686	684	682	680	678	676	674	672	670	668	666	664	8,100	8,100	
1h	Phillips Upgrade Tank #4 for FDEP	1,080	1,077	1,074	1,071	1,068	1,065	1,061	1,059	1,056	1,052	1,049	1,047	12,759	12,759	
1i	Gannon Unit 5 Classifier Replacement	26,865	26,663	26,461	26,260	26,058	25,857	25,655	25,453	25,252	25,051	24,849	24,647	309,071		309,071
1j	Gannon Unit 6 Classifier Replacement	31,023	30,797	30,571	30,346	30,120	29,894	29,669	29,443	29,218	28,992	28,766	28,541	357,380		357,380
1k	Big Bend Unit 1 Classifier Replacement	15,235	15,197	15,160	15,123	15,086	15,048	15,011	14,974	14,937	14,899	14,862	14,825	180,357		180,357
1l	Big Bend Unit 2 Classifier Replacement	11,119	11,093	11,066	11,040	11,015	10,988	10,962	10,936	10,909	10,883	10,856	10,830	131,697		131,697
1m	Gannon Coal Crusher (NO_x Control)	113,776	112,948	112,119	111,290	110,462	109,634	108,805	107,977	107,148	106,319	105,492	104,663	1,310,633		1,310,633
1n	Big Bend Units 1 & 2 FGD	1,039,906	1,036,932	1,033,958	1,030,983	1,028,010	1,025,035	1,022,061	1,019,087	1,016,112	1,013,138	1,010,164	1,007,189	12,282,575		12,282,575
1o	Big Bend Section 114 Mercury Testing Platform	1,333	1,330	1,329	1,326	1,324	1,322	1,320	1,318	1,316	1,314	1,312	1,310	15,854		15,854
1p	Big Bend FGD Optimization and Utilization	229,423	254,780	257,043	260,561	260,464	260,057	259,390	259,039	258,688	258,201	257,714	257,197	3,072,557		3,072,557
1q	Big Bend PM Minimization and Monitoring	7,944	8,885	9,695	10,254	11,018	11,259	11,573	12,088	12,852	21,754	33,748	48,608	199,678		199,678
1r	Big Bend NO_x Emissions Reduction	13,077	13,270	13,596	15,156	17,095	17,754	19,060	21,218	23,103	26,120	30,612	35,195	245,256		245,256
1s	Polk NO_x Emissions Reduction	0	0	0	0	0	0	0	180	519	817	1,060	1,704	4,280		4,280
2.	Total Investment Projects - Recoverable Costs	1,659,474	1,681,212	1,679,904	1,680,866	1,678,800	1,674,619	1,670,896	1,668,727	1,666,689	1,673,741	1,685,310	1,700,208	20,120,446	$305,082	$19,815,364
3.	Recoverable Costs Allocated to Energy	1,633,761	1,655,610	1,654,370	1,655,367	1,653,336	1,649,189	1,645,502	1,643,367	1,641,365	1,648,452	1,660,057	1,674,988	19,815,364		
4.	Recoverable Costs Allocated to Demand	25,713	25,602	25,534	25,499	25,464	25,430	25,394	25,360	25,324	25,289	25,253	25,220	305,082		
5.	Retail Energy Jurisdictional Factor	0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077			
6.	Retail Demand Jurisdictional Factor	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189			
7.	Jurisdictional Energy Recoverable Costs (B)	1,607,102	1,640,047	1,614,711	1,596,571	1,602,079	1,602,718	1,597,708	1,592,739	1,587,776	1,589,969	1,617,236	1,630,950	19,279,606		
8.	Jurisdictional Demand Recoverable Costs (C)	23,628	23,526	23,464	23,432	23,399	23,368	23,335	23,304	23,271	23,239	23,205	23,175	280,346		
9.	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$1,630,730	$1,663,573	$1,638,175	$1,620,003	$1,625,478	$1,626,086	$1,621,043	$1,616,043	$1,611,047	$1,613,208	$1,640,441	$1,654,125	$19,559,952		

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

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FORM 42-7A
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
January 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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	(1,489,185)	(1,508,411)	(1,527,637)	(1,546,863)	(1,566,089)	(1,585,315)	(1,604,541)	(1,623,767)	(1,642,993)	(1,662,219)	(1,681,445)	(1,700,671)	(1,719,897)	
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)	$6,750,473	6,731,247	6,712,021	6,692,795	6,673,569	6,654,343	6,635,117	6,615,891	6,596,665	6,577,439	6,558,213	6,538,987	6,519,761	
6.	Average Net Investment		6,740,860	6,721,634	6,702,408	6,683,182	6,663,956	6,644,730	6,625,504	6,606,278	6,587,052	6,567,826	6,548,600	6,529,374	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		49,567	49,425	49,284	49,143	49,001	48,860	48,718	48,577	48,436	48,294	48,153	48,012	585,470
	b. Debt Component (*Line 6 x 2.82% x 1/12*)		15,841	15,796	15,751	15,705	15,660	15,615	15,570	15,525	15,480	15,434	15,389	15,344	187,110
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)		84,634	84,447	84,261	84,074	83,887	83,701	83,514	83,328	83,142	82,954	82,768	82,582	1,003,292
	a. Recoverable Costs Allocated to Energy		84,634	84,447	84,261	84,074	83,887	83,701	83,514	83,328	83,142	82,954	82,768	82,582	1,003,292
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11.	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12.	*Retail Energy*-Related Recoverable Costs (D)		83,253	83,653	82,241	81,088	81,286	81,342	81,088	80,761	80,428	80,011	80,633	80,411	976,195
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)		$83,253	$83,653	$82,241	$81,088	$81,286	$81,342	$81,088	$80,761	$80,428	$80,011	$80,633	$80,411	$976,195

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. 030007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-8A
FILED: APRIL 1, 2003

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
January 2002 to December 2002

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	Actual Jan-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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	(1,252,514)	(1,266,759)	(1,281,004)	(1,295,249)	(1,309,494)	(1,323,739)	(1,337,984)	(1,352,229)	(1,366,474)	(1,380,719)	(1,394,964)	(1,409,209)	(1,423,454)	
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)	$3,765,220	3,750,975	3,736,730	3,722,485	3,708,240	3,693,995	3,679,750	3,665,505	3,651,260	3,637,015	3,622,770	3,608,525	3,594,280	
6.	Average Net Investment		3,758,098	3,743,853	3,729,608	3,715,363	3,701,118	3,686,873	3,672,628	3,658,383	3,644,138	3,629,893	3,615,648	3,601,403	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		27,634	27,529	27,424	27,320	27,215	27,110	27,005	26,901	26,796	26,691	26,586	26,482	324,693
	b. *Debt* Component (Line 6 x 2.82% x 1/12)		8,832	8,798	8,765	8,731	8,698	8,664	8,631	8,597	8,564	8,530	8,497	8,463	103,770
8.	Investment Expenses														
	a. Depreciation (C)		14,245	14,245	14,245	14,245	14,245	14,245	14,245	14,245	14,245	14,245	14,245	14,245	170,940
	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)		50,711	50,572	50,434	50,296	50,158	50,019	49,881	49,743	49,605	49,466	49,328	49,190	599,403
	a. Recoverable Costs Allocated to Energy		50,711	50,572	50,434	50,296	50,158	50,019	49,881	49,743	49,605	49,466	49,328	49,190	599,403
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11.	*Demand Jurisdictional Factor*		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12.	Retail Energy-Related Recoverable Costs (D)		49,884	50,097	49,225	48,510	48,603	48,610	48,432	48,211	47,985	47,711	48,056	47,897	583,221
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)		$49,884	$50,097	$49,225	$48,510	$48,603	$48,610	$48,432	$48,211	$47,985	$47,711	$48,056	$47,897	$583,221

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 3.5% and 3.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

EXHIBIT NO._____
DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
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FILED: APRIL 1, 2003

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
January 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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	(167,945)	(169,894)	(171,843)	(173,792)	(175,741)	(177,690)	(179,639)	(181,588)	(183,537)	(185,486)	(187,435)	(189,384)	(191,333)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$698,266	696,317	694,368	692,419	690,470	688,521	686,572	684,623	682,674	680,725	678,776	676,827	674,878	
6.	Average Net Investment		697,292	695,343	693,394	691,445	689,496	687,547	685,598	683,649	681,700	679,751	677,802	675,853	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,127	5,113	5,099	5,084	5,070	5,056	5,041	5,027	5,013	4,998	4,984	4,970	60,582
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,639	1,634	1,629	1,625	1,620	1,616	1,611	1,607	1,602	1,597	1,593	1,588	19,361
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)		8,715	8,696	8,677	8,658	8,639	8,621	8,601	8,583	8,564	8,544	8,526	8,507	103,331
	a. Recoverable Costs Allocated to Energy		8,715	8,696	8,677	8,658	8,639	8,621	8,601	8,583	8,564	8,544	8,526	8,507	103,331
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11.	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12.	Retail Energy-Related Recoverable Costs (D)		8,573	8,614	8,469	8,350	8,371	8,378	8,351	8,319	8,284	8,241	8,306	8,283	100,539
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)		$8,573	$8,614	$8,469	$8,350	$8,371	$8,378	$8,351	$8,319	$8,284	$8,241	$8,306	$8,283	$100,539

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

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DOCKET NO. 030007-EI
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
January 2002 to December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Gannon Ignition Oil Tank
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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)	$544,745	544,745	544,745	544,745	544,745	544,745	544,745	544,745	544,745	544,745	544,745	544,745	544,745	
3.	Less: Accumulated Depreciation	(262,903)	(271,982)	(281,061)	(290,140)	(299,219)	(308,299)	(317,379)	(326,458)	(335,537)	(344,616)	(353,695)	(362,774)	(371,853)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	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)*	$15,842	6,762	-	-	-	-	-	-	-	-	-	-	-	
6.	Average Net Investment		11,302	3,381	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		83	25	0	0	0	0	0	0	0	0	0	0	108
	b. *Debt Component (Line 6 x 2.82% x 1/12)*		27	8	0	0	0	0	0	0	0	0	0	0	35
8.	Investment Expenses														
	a. Depreciation (D)		9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	108,949
	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)		9,189	9,112	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	109,091
	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		9,189	9,112	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	9,079	109,091
10.	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11.	*Demand Jurisdictional Factor*		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	*Retail Demand-Related Recoverable Costs (F)*		8,444	8,373	8,343	8,343	8,343	8,343	8,343	8,343	8,343	8,343	8,343	8,343	100,247
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,444	$8,373	$8,343	$8,343	$8,343	$8,343	$8,343	$8,343	$8,343	$8,343	$8,343	$8,343	$100,247

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 312.50

(B) Represents the Capital Costs of the Gannon Ignition Oil Tank currently recovered through base 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 rate is 20%; Docket No. 000686-EI, Order No. PSC-00-2275-PAA-EI and Docket No. 000007-EI, Order No. PSC-00-2391-FOF-EI

(E) Line 9a x Line 10

(F) 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 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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	(41,572)	(42,733)	(43,894)	(45,055)	(46,216)	(47,377)	(48,538)	(49,699)	(50,860)	(52,021)	(53,182)	(54,343)	(55,504)	
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*)	$456,006	454,845	453,684	452,523	451,362	450,201	449,040	447,879	446,718	445,557	444,396	443,235	442,074	
6.	Average Net Investment		455,426	454,265	453,104	451,943	450,782	449,621	448,460	447,299	446,138	444,977	443,816	442,655	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,349	3,340	3,332	3,323	3,315	3,306	3,298	3,289	3,281	3,272	3,263	3,255	39,623
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,070	1,068	1,065	1,062	1,059	1,057	1,054	1,051	1,048	1,046	1,043	1,040	12,663
8.	Investment Expenses														
	a. Depreciation (C)		1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	1,161	13,932
	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)		5,580	5,569	5,558	5,546	5,535	5,524	5,513	5,501	5,490	5,479	5,467	5,456	66,218
	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		5,580	5,569	5,558	5,546	5,535	5,524	5,513	5,501	5,490	5,479	5,467	5,456	66,218
10.	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11.	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
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)		5,128	5,117	5,107	5,096	5,086	5,076	5,066	5,055	5,045	5,035	5,024	5,014	60,849
14.	Total Jurisdictional Recoverable Costs (*Lines 12 + 13*)		$5,128	$5,117	$5,107	$5,096	$5,086	$5,076	$5,066	$5,055	$5,045	$5,035	$5,024	$5,014	$60,849

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 2.8%*
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-8A
FILED: APRIL 1, 2003

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
January 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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	(68,404)	(70,314)	(72,224)	(74,134)	(76,044)	(77,954)	(79,864)	(81,774)	(83,684)	(85,594)	(87,504)	(89,414)	(91,324)	
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)	$749,997	748,087	746,177	744,267	742,357	740,447	738,537	736,627	734,717	732,807	730,897	728,987	727,077	
6.	Average Net Investment		749,042	747,132	745,222	743,312	741,402	739,492	737,582	735,672	733,762	731,852	729,942	728,032	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,508	5,494	5,480	5,466	5,452	5,438	5,424	5,410	5,395	5,381	5,367	5,353	65,168
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,760	1,756	1,751	1,747	1,742	1,738	1,733	1,729	1,724	1,720	1,715	1,711	20,826
8.	Investment Expenses														
	a. Depreciation (C)		1,910	1,910	1,910	1,910	1,910	1,910	1,910	1,910	1,910	1,910	1,910	1,910	22,920
	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)		9,178	9,160	9,141	9,123	9,104	9,086	9,067	9,049	9,029	9,011	8,992	8,974	108,914
	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		9,178	9,160	9,141	9,123	9,104	9,086	9,067	9,049	9,029	9,011	8,992	8,974	108,914
10.	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11.	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
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)		8,434	8,417	8,400	8,383	8,366	8,349	8,332	8,315	8,297	8,280	8,263	8,246	100,082
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,434	$8,417	$8,400	$8,383	$8,366	$8,349	$8,332	$8,315	$8,297	$8,280	$8,263	$8,246	$100,082

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 2.8%
(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 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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	(7,128)	(7,328)	(7,528)	(7,728)	(7,928)	(8,128)	(8,328)	(8,528)	(8,728)	(8,928)	(9,128)	(9,328)	(9,528)	
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)	$50,149	49,949	49,749	49,549	49,349	49,149	48,949	48,749	48,549	48,349	48,149	47,949	47,749	
6.	Average Net Investment		50,049	49,849	49,649	49,449	49,249	49,049	48,849	48,649	48,449	48,249	48,049	47,849	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		368	367	365	364	362	361	359	358	356	355	353	352	4,320
	b. Debt Component (Line 6 x 2.82% x 1/12)		118	117	117	116	116	115	115	114	114	113	113	112	1,380
8.	Investment Expenses														
	a. Depreciation (C)		200	200	200	200	200	200	200	200	200	200	200	200	2,400
	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)		686	684	682	680	678	676	674	672	670	668	666	664	8,100
	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		686	684	682	680	678	676	674	672	670	668	666	664	8,100
10.	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11.	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
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)		630	629	627	625	623	621	619	618	616	614	612	610	7,444
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$630	$629	$627	$625	$623	$621	$619	$618	$616	$614	$612	$610	$7,444

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 4.2%
(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 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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	(11,675)	(11,992)	(12,309)	(12,626)	(12,943)	(13,260)	(13,577)	(13,894)	(14,211)	(14,528)	(14,845)	(15,162)	(15,479)	
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)	$78,797	78,480	78,163	77,846	77,529	77,212	76,895	76,578	76,261	75,944	75,627	75,310	74,993	
6.	Average Net Investment		78,639	78,322	78,005	77,688	77,371	77,054	76,737	76,420	76,103	75,786	75,469	75,152	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		578	576	574	571	569	567	564	562	560	557	555	553	6,786
	b. Debt Component (Line 6 x 2.82% x 1/12)		185	184	183	183	182	181	180	180	179	178	177	177	2,169
8.	Investment Expenses														
	a. Depreciation (C)		317	317	317	317	317	317	317	317	317	317	317	317	3,804
	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)		1,080	1,077	1,074	1,071	1,068	1,065	1,061	1,059	1,056	1,052	1,049	1,047	12,759
	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		1,080	1,077	1,074	1,071	1,068	1,065	1,061	1,059	1,056	1,052	1,049	1,047	12,759
10.	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11.	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
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)		992	990	987	984	981	979	975	973	970	967	964	962	11,724
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$992	$990	$987	$984	$981	$979	$975	$973	$970	$967	$964	$962	$11,724

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 4.2%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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DOCKET NO. 030007-EI
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
January 2002 to December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Gannon Unit 5 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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)	$1,246,700	1,246,700	1,246,700	1,246,700	1,246,700	1,246,700	1,246,700	1,246,700	1,246,700	1,246,700	1,246,700	1,246,700	1,246,700	
3	Less: Accumulated Depreciation	(609,012)	(629,790)	(650,569)	(671,347)	(692,125)	(712,904)	(733,682)	(754,460)	(775,239)	(796,017)	(816,795)	(837,574)	(858,352)	
4	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$637,688	616,910	596,131	575,353	554,575	533,796	513,018	492,240	471,461	450,683	429,905	409,126	388,348	
6	Average Net Investment		627,299	606,521	585,742	564,964	544,186	523,407	502,629	481,851	461,072	440,294	419,516	398,737	
7	Return on Average Net Investment														
	a. *Equity Component Grossed Up For Taxes (B)*		4,613	4,460	4,307	4,154	4,001	3,849	3,696	3,543	3,390	3,238	3,085	2,932	45,268
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,474	1,425	1,376	1,328	1,279	1,230	1,181	1,132	1,084	1,035	986	937	14,467
8	Investment Expenses														
	a. Depreciation (C)		20,778	20,778	20,778	20,778	20,778	20,778	20,778	20,778	20,778	20,778	20,778	20,778	249,336
	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)*		26,865	26,663	26,461	26,260	26,058	25,857	25,655	25,453	25,252	25,051	24,849	24,647	309,071
	a. Recoverable Costs Allocated to Energy		26,865	26,663	26,461	26,260	26,058	25,857	25,655	25,453	25,252	25,051	24,849	24,647	309,071
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12	Retail Energy-Related Recoverable Costs (D)		26,427	26,412	25,827	25,327	25,250	25,128	24,910	24,669	24,428	24,162	24,208	23,999	300,747
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)		$26,427	$26,412	$25,827	$25,327	$25,250	$25,128	$24,910	$24,669	$24,428	$24,162	$24,208	$23,999	$300,747

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) Applicable depreciation rate is 20%; Docket No. 000686-EI, Order No. PSC-00-2275-PAA-EI and Docket No. 000007-EI, Order No. PSC-00-2391-FOF-EI

(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 2002 to December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Gannon Unit 6 Classifier Replacement
(in Dollars)

Line	Description	*Beginning of* Period Amount	Actual Jan-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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)	$1,394,717	1,394,717	1,394,717	1,394,717	1,394,717	1,394,717	1,394,717	1,394,717	1,394,717	1,394,717	1,394,717	1,394,717	1,394,717	
3	Less: Accumulated Depreciation	(581,590)	(604,835)	(628,080)	(651,325)	(674,570)	(697,815)	(721,060)	(744,305)	(767,550)	(790,795)	(814,040)	(837,285)	(860,530)	
4	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$813,127	789,882	766,637	743,392	720,147	696,902	673,657	650,412	627,167	603,922	580,677	557,432	534,187	
6	Average Net Investment		801,504	778,259	755,014	731,769	708,524	685,279	662,034	638,789	615,544	592,299	569,054	545,809	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,894	5,723	5,552	5,381	5,210	5,039	4,868	4,697	4,526	4,355	4,184	4,013	59,442
	b. *Debt Component (Line 6 x 2.82% x 1/12)*		1,884	1,829	1,774	1,720	1,665	1,610	1,556	1,501	1,447	1,392	1,337	1,283	18,998
8	Investment Expenses														
	a. Depreciation (C)		23,245	23,245	23,245	23,245	23,245	23,245	23,245	23,245	23,245	23,245	23,245	23,245	278,940
	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)		31,023	30,797	30,571	30,346	30,120	29,894	29,669	29,443	29,218	28,992	28,766	28,541	357,380
	a. Recoverable Costs Allocated to Energy		31,023	30,797	30,571	30,346	30,120	29,894	29,669	29,443	29,218	28,992	28,766	28,541	357,380
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12	Retail Energy-Related Recoverable Costs (D)		30,517	30,508	29,838	29,268	29,186	29,052	28,807	28,536	28,264	27,963	28,024	27,791	347,754
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)		$30,517	$30,508	$29,838	$29,268	$29,186	$29,052	$28,807	$28,536	$28,264	$27,963	$28,024	$27,791	$347,754

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 312.56

(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 20%; Docket No. 000686-EI, Order No. PSC-00-2275-PAA-EI and Docket No. 000007-EI, Order No. PSC-00-2391-FOF-EI

(D) Line 9a x Line 10

(E) Line 9b x Line 11

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FILED: APRIL 1, 2003

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
January 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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	(139,940)	(143,779)	(147,618)	(151,457)	(155,296)	(159,135)	(162,974)	(166,813)	(170,652)	(174,491)	(178,330)	(182,169)	(186,008)	
4	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$1,176,317	1,172,478	1,168,639	1,164,800	1,160,961	1,157,122	1,153,283	1,149,444	1,145,605	1,141,766	1,137,927	1,134,088	1,130,249	
6	Average Net Investment		1,174,398	1,170,559	1,166,720	1,162,881	1,159,042	1,155,203	1,151,364	1,147,525	1,143,686	1,139,847	1,136,008	1,132,169	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,636	8,607	8,579	8,551	8,523	8,494	8,466	8,438	8,410	8,381	8,353	8,325	101,763
	b. Debt Component (Line 6 x 2.82% x 1/12)		2,760	2,751	2,742	2,733	2,724	2,715	2,706	2,697	2,688	2,679	2,670	2,661	32,526
8	Investment Expenses														
	a. Depreciation (C)		3,839	3,839	3,839	3,839	3,839	3,839	3,839	3,839	3,839	3,839	3,839	3,839	46,068
	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)		15,235	15,197	15,160	15,123	15,086	15,048	15,011	14,974	14,937	14,899	14,862	14,825	180,357
	a. Recoverable Costs Allocated to Energy		15,235	15,197	15,160	15,123	15,086	15,048	15,011	14,974	14,937	14,899	14,862	14,825	180,357
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12	Retail Energy-Related Recoverable Costs (D)		14,986	15,054	14,797	14,586	14,618	14,624	14,575	14,513	14,449	14,370	14,479	14,435	175,486
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)		$14,986	$15,054	$14,797	$14,586	$14,618	$14,624	$14,575	$14,513	$14,449	$14,370	$14,479	$14,435	$175,486

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 3.5%
(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 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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	(116,574)	(119,282)	(121,990)	(124,698)	(127,406)	(130,114)	(132,822)	(135,530)	(138,238)	(140,946)	(143,654)	(146,362)	(149,070)	
4	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$868,220	865,512	862,804	860,096	857,388	854,680	851,972	849,264	846,556	843,848	841,140	838,432	835,724	
6	Average Net Investment		866,866	864,158	861,450	858,742	856,034	853,326	850,618	847,910	845,202	842,494	839,786	837,078	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		6,374	6,354	6,334	6,314	6,295	6,275	6,255	6,235	6,215	6,195	6,175	6,155	75,176
	b. Debt Component (Line 6 x 2.82% x 1/12)		2,037	2,031	2,024	2,018	2,012	2,005	1,999	1,993	1,986	1,980	1,973	1,967	24,025
8	Investment Expenses														
	a. Depreciation (C)		2,708	2,708	2,708	2,708	2,708	2,708	2,708	2,708	2,708	2,708	2,708	2,708	32,496
	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)		11,119	11,093	11,066	11,040	11,015	10,988	10,962	10,936	10,909	10,883	10,856	10,830	131,697
	a. Recoverable Costs Allocated to Energy		11,119	11,093	11,066	11,040	11,015	10,988	10,962	10,936	10,909	10,883	10,856	10,830	131,697
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12	Retail Energy-Related Recoverable Costs (D)		10,938	10,989	10,801	10,648	10,674	10,678	10,644	10,599	10,553	10,497	10,576	10,545	128,142
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)		$10,938	$10,989	$10,801	$10,648	$10,674	$10,678	$10,644	$10,599	$10,553	$10,497	$10,576	$10,545	$128,142

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 3.3%
(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 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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)	$5,122,774	5,122,774	5,122,774	5,122,774	5,122,774	5,122,774	5,122,774	5,122,774	5,122,774	5,122,774	5,122,774	5,122,774	5,122,774	
3	*Less: Accumulated Depreciation*	(2,153,635)	(2,239,015)	(2,324,395)	(2,409,775)	(2,495,155)	(2,580,535)	(2,665,915)	(2,751,295)	(2,836,675)	(2,922,055)	(3,007,435)	(3,092,815)	(3,178,195)	
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)	$2,969,139	2,883,759	2,798,379	2,712,999	2,627,619	2,542,239	2,456,859	2,371,479	2,286,099	2,200,719	2,115,339	2,029,959	1,944,579	
6	Average Net Investment		2,926,449	2,841,069	2,755,689	2,670,309	2,584,929	2,499,549	2,414,169	2,328,789	2,243,409	2,158,029	2,072,649	1,987,269	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		21,519	20,891	20,263	19,635	19,007	18,380	17,752	17,124	16,496	15,868	15,241	14,613	216,789
	b. Debt Component (Line 6 x 2.82% x 1/12)		6,877	6,677	6,476	6,275	6,075	5,874	5,673	5,473	5,272	5,071	4,871	4,670	69,284
8	Investment Expenses														
	a. Depreciation (C)		85,380	85,380	85,380	85,380	85,380	85,380	85,380	85,380	85,380	85,380	85,380	85,380	1,024,560
	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)		113,776	112,948	112,119	111,290	110,462	109,634	108,805	107,977	107,148	106,319	105,492	104,663	1,310,633
	a. Recoverable Costs Allocated to Energy		113,776	112,948	112,119	111,290	110,462	109,634	108,805	107,977	107,148	106,319	105,492	104,663	1,310,633
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12	Retail Energy-Related Recoverable *Costs (D)*		111,919	111,886	109,431	107,337	107,038	106,545	105,645	104,650	103,650	102,547	102,771	101,911	1,275,330
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)		$111,919	$111,886	$109,431	$107,337	$107,038	$106,545	$105,645	$104,650	$103,650	$102,547	$102,771	$101,911	$1,275,330

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 312.50

(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 20%; Docket No. 000686-EI, Order No. PSC-00-2275-PAA-EI and Docket No. 000007-EI, Order No. PSC-00-2391-FOF-EI

(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 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual *Oct-02*	Actual Nov-02	Actual Dec-02	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	(5,083)	(5,294)	(5,505)	(5,716)	(5,927)	(6,138)	(6,349)	(6,560)	(6,771)	(6,982)	(7,193)	(7,404)	(7,615)	
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)	$115,654	115,443	115,232	115,021	114,810	114,599	114,388	114,177	113,966	113,755	113,544	113,333	113,122	
6	Average Net Investment		115,549	115,338	115,127	114,916	114,705	114,494	114,283	114,072	113,861	113,650	113,439	113,228	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		850	848	847	845	843	842	840	839	837	836	834	833	10,094
	b. Debt Component (Line 6 x 2.82% x 1/12)		272	271	271	270	270	269	269	268	268	267	267	266	3,228
8	Investment Expenses														
	a. Depreciation (C)		211	211	211	211	211	211	211	211	211	211	211	211	2,532
	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)		1,333	1,330	1,329	1,326	1,324	1,322	1,320	1,318	1,316	1,314	1,312	1,310	15,854
	a. Recoverable Costs Allocated to Energy		1,333	1,330	1,329	1,326	1,324	1,322	1,320	1,318	1,316	1,314	1,312	1,310	15,854
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12	Retail Energy-Related Recoverable Costs (D)		1,311	1,317	1,297	1,279	1,283	1,285	1,282	1,277	1,273	1,267	1,278	1,276	15,425
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)		$1,311	$1,317	$1,297	$1,279	$1,283	$1,285	$1,282	$1,277	$1,273	$1,267	$1,278	$1,276	$15,425

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 2.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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Calculation of the Actual Amount for the Period
January 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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	(7,395,099)	(7,701,627)	(8,008,155)	(8,314,683)	(8,621,211)	(8,927,739)	(9,234,267)	(9,540,795)	(9,847,323)	(10,153,851)	(10,460,379)	(10,766,907)	(11,073,435)	
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)	$75,734,622	75,428,094	75,121,566	74,815,038	74,508,510	74,201,982	73,895,454	73,588,926	73,282,398	72,975,870	72,669,342	72,362,814	72,056,286	
6	Average Net Investment		75,581,358	75,274,830	74,968,302	74,661,774	74,355,246	74,048,718	73,742,190	73,435,662	73,129,134	72,822,606	72,516,078	72,209,550	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		555,762	553,508	551,254	549,000	546,747	544,493	542,239	539,985	537,731	535,477	533,223	530,969	6,520,388
	b. Debt Component (Line 6 x 2.82% x 1/12)		177,616	176,896	176,176	175,455	174,735	174,014	173,294	172,574	171,853	171,133	170,413	169,692	2,083,851
8	Investment Expenses														
	a. Depreciation (C)		306,528	306,528	306,528	306,528	306,528	306,528	306,528	306,528	306,528	306,528	306,528	306,528	3,678,336
	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)		1,039,906	1,036,932	1,033,958	1,030,983	1,028,010	1,025,035	1,022,061	1,019,087	1,016,112	1,013,138	1,010,164	1,007,189	12,282,575
	a. Recoverable Costs Allocated to Energy		1,039,906	1,036,932	1,033,958	1,030,983	1,028,010	1,025,035	1,022,061	1,019,087	1,016,112	1,013,138	1,010,164	1,007,189	12,282,575
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12	Retail Energy-Related Recoverable Costs (D)		1,022,937	1,027,186	1,009,171	994,364	996,140	996,151	992,375	987,691	982,937	977,196	984,107	980,708	11,950,963
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)		$1,022,937	$1,027,186	$1,009,171	$994,364	$996,140	$996,151	$992,375	$987,691	$982,937	$977,196	$984,107	$980,708	$11,950,963

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 4.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Actual Amount for the Period
January 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	End of Period Total
1	Investments														
	a. Expenditures/Additions		$13,345	$161,674	($6,666)	$118,820	$26,044	$21,696	$44,269	$63,304	$95,482	$1,740,666	$731,192	$2,331,000	$5,340,826
	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)	$129,677	134,206	210,019	186,420	226,101	240,723	240,870	240,178	240,178	240,178	240,178	247,178	247,178	
3	Less: Accumulated Depreciation	(4,838)	(5,222)	(5,703)	(6,247)	(6,811)	(7,441)	(8,088)	(8,735)	(9,381)	(10,027)	(10,673)	(11,327)	(11,990)	
4	CWIP - Non-Interest Bearing	647,757	656,573	742,435	759,367	838,506	849,927	871,476	916,437	979,741	1,075,223	2,815,889	3,540,081	5,871,081	
5	Net Investment (Lines 2 + 3 + 4) (B)	$772,596	785,557	946,751	939,540	1,057,796	1,083,209	1,104,258	1,147,880	1,210,538	1,305,374	3,045,394	3,775,932	6,106,269	
6	Average Net Investment		779,077	866,154	943,146	998,668	1,070,503	1,093,734	1,126,069	1,179,209	1,257,956	2,175,384	3,410,663	4,941,101	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		5,729	6,369	6,935	7,343	7,872	8,042	8,280	8,671	9,250	15,996	25,079	36,333	145,899
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,831	2,035	2,216	2,347	2,516	2,570	2,646	2,771	2,956	5,112	8,015	11,612	46,627
8	Investment Expenses														
	a. Depreciation (D)		384	481	544	564	630	647	647	646	646	646	654	663	7,152
	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)		7,944	8,885	9,695	10,254	11,018	11,259	11,573	12,088	12,852	21,754	33,748	48,608	199,678
	a. Recoverable Costs Allocated to Energy		7,944	8,885	9,695	10,254	11,018	11,259	11,573	12,088	12,852	21,754	33,748	48,608	199,678
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12	Retail Energy-Related Recoverable Costs (E)		7,814	8,801	9,463	9,890	10,676	10,942	11,237	11,716	12,432	20,982	32,877	47,330	194,160
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)		$7,814	$8,801	$9,463	$9,890	$10,676	$10,942	$11,237	$11,716	$12,432	$20,982	$32,877	$47,330	$194,160

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 3.5% and 2.9%
(E) Line 9a x Line 10
(F) 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 2002 to December 2002

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-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	End of Period Total
1	Investments														
	a. Expenditures/Additions		$15,201	$24,376	$42,688	$278,973	$120,719	$15,226	$253,960	$190,589	$198,132	$423,743	$502,030	$442,740	$2,508,377
	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	1,340,182	1,355,383	1,379,759	1,422,447	1,701,420	1,822,139	1,837,365	2,091,325	2,281,914	2,480,046	2,903,789	3,405,819	3,848,559	
5	Net Investment (Lines 2 + 3 + 4)	$1,340,182	1,355,383	1,379,759	1,422,447	1,701,420	1,822,139	1,837,365	2,091,325	2,281,914	2,480,046	2,903,789	3,405,819	3,848,559	
6	Average Net Investment		1,347,783	1,367,571	1,401,103	1,561,934	1,761,780	1,829,752	1,964,345	2,186,620	2,380,980	2,691,918	3,154,804	3,627,189	
7	*Return on Average Net Investment*														
	a. Equity Component Grossed Up For Taxes (B)		9,910	10,056	10,303	11,485	12,955	13,454	14,444	16,079	17,508	19,794	23,198	26,671	185,857
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,167	3,214	3,293	3,671	4,140	4,300	4,616	5,139	5,595	6,326	7,414	8,524	59,399
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)		13,077	13,270	13,596	15,156	17,095	17,754	19,060	21,218	23,103	26,120	30,612	35,195	245,256
	a. Recoverable Costs Allocated to Energy		13,077	13,270	13,596	15,156	17,095	17,754	19,060	21,218	23,103	26,120	30,612	35,195	245,256
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12	Retail Energy-Related Recoverable Costs (D)		12,864	13,145	13,270	14,618	16,565	17,254	18,506	20,564	22,349	25,193	29,822	34,270	238,420
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)		$12,864	$13,145	$13,270	$14,618	$16,565	$17,254	$18,506	$20,564	$22,349	$25,193	$29,822	$34,270	$238,420

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 3.5% and 3.3%

(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 2002 to December 2002

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$37,125	$32,754	$28,671	$21,397	$111,169	$231,116
	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	37,125	69,879	98,550	119,947	231,116	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	37,125	69,879	98,550	119,947	231,116	
6	Average Net Investment		0	0	0	0	0	0	0	18,563	53,502	84,215	109,249	175,532	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	136	393	619	803	1,291	3,242
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	44	126	198	257	413	1,038
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	180	519	817	1,060	1,704	4,280
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	180	519	817	1,060	1,704	4,280
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	174	502	788	1,033	1,659	4,156
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)		$0	$0	$0	$0	$0	$0	$0	$174	$502	$788	$1,033	$1,659	$4,156

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 5.3%
(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 2002 to December 2002

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	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		21,599	12,048	8,186	17,960	(39,113)	(10,248)	(18,584)	(15,236)	(20,474)	(21,055)	(21,730)	(90,900)	(177,547)
8	Net Expenses		21,599	12,048	8,186	17,960	(39,113)	(10,248)	(18,584)	(15,236)	(20,474)	(21,055)	(21,730)	(90,900)	(177,547)
9	Total System Recoverable Expenses (Lines 6 + 7)		21,599	12,048	8,186	17,960	(39,113)	(10,248)	(18,584)	(15,236)	(20,474)	(21,055)	(21,730)	(90,900)	(177,547)
	a Recoverable Costs Allocated to Energy		21,599	12,048	8,186	17,960	(39,113)	(10,248)	(18,584)	(15,236)	(20,474)	(21,055)	(21,730)	(90,900)	(177,547)
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9836826	0.9906009	0.9760274	0.9644814	0.9689987	0.9718219	0.9709545	0.9691919	0.9673511	0.9645237	0.9742055	0.9737077	
11	Demand Jurisdictional Factor		0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
12	Retail Energy-Related Recoverable Costs (B)		21,247	11,935	7,990	17,322	(37,900)	(9,959)	(18,044)	(14,767)	(19,806)	(20,308)	(21,169)	(88,510)	(171,969)
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)		$21,247	$11,935	$7,990	$17,322	($37,900)	($9,959)	($18,044)	($14,767)	($19,806)	($20,308)	($21,169)	($88,510)	($171,969)

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

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DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
FILED: AUGUST 8, 2003

ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2003 THROUGH DECEMBER 2003

42-1E THROUGH 42-8E

EXHIBIT NO._____
DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2003 THROUGH DECEMBER 2003

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Tampa Electric Company Form 42 - 1E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
January 2003 to December 2003
(in Dollars)

Line	Period Amount
1. Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	($301,784)
2. Interest Provision (Form 42-2E, Line 6)	13,643
3. Sum of Current Period Adjustments (Form 42-2E, Line 10)	124,338
4. Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2004 to December 2004 (Lines 1 + 2 + 3)	($163,803)

EXHIBIT NO._____
DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 1
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FORM 42-1E
FILED: AUGUST 8, 2003

Form 42 - 2E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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	$2,419,001	$2,443,498	$2,496,094	$2,282,817	$2,023,608	$2,038,474	$26,092,182
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	2,623,678	2,648,175	2,700,771	2,487,494	2,228,285	2,243,152	28,548,307
4. Jurisdictional ECRC Costs													
a. O & M Activities (Form 42-5E, Line 9)	420,847	388,081	481,446	431,221	950,385	638,495	603,982	561,540	642,929	586,797	641,704	1,268,314	7,615,741
b. Capital Investment Projects (Form 42-7E, Line 9)	1,776,823	1,779,994	1,749,581	1,763,578	1,760,842	1,763,790	1,761,659	1,760,398	1,771,871	1,771,317	1,786,108	1,788,389	21,234,350
c. Total Jurisdictional ECRC Costs	2,197,670	2,168,075	2,231,027	2,194,799	2,711,227	2,402,285	2,365,641	2,321,938	2,414,800	2,358,114	2,427,812	3,056,703	28,850,091
5. Over/Under Recovery (Line 3 - Line 4c)	118,459	(7,793)	(240,011)	(77,069)	(261,447)	179,530	258,037	326,237	285,971	129,380	(199,527)	(813,551)	(301,784)
6. Interest Provision (Form 42-3E, Line 10)	2,226	2,030	1,623	1,233	873	578	546	928	1,391	1,399	1,001	(185)	13,643
7. Beginning Balance True-Up & Interest Provision	2,456,125	2,496,471	2,286,031	1,842,966	1,562,453	1,097,202	1,072,633	1,126,539	1,249,027	1,331,712	1,257,814	854,611	2,456,125
a. Deferred True-Up from January to December 2002 (Order No. PSC-xx-xxxx-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)	1,915,565	1,829,463	1,386,398	1,105,885	640,634	616,065	669,971	792,459	875,144	801,246	398,043	(620,371)	(744,709)
10. Adjustment to Period True-Up Including Interest	124,338	0	0	0	0	0	0	0	0	0	0	0	124,338
11. End of Period Total Net True-Up (Lines 9 + 10)	$2,039,903	$1,829,463	$1,386,398	$1,105,885	$640,634	$616,065	$669,971	$792,459	$875,144	$801,246	$398,043	($620,371)	($620,371)

EXHIBIT NO. _____
DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-2E
FILED: AUGUST 8, 2003

Form 42 - 3E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated Dec-03	End of Period Total
1. Beginning Balance True-Up Amount (Form 42-2E, Line 7 +7a + 10)	$2,123,895	$2,039,903	$1,829,463	$1,386,398	$1,105,885	$640,634	$616,065	$669,971	$792,459	$875,144	$801,246	$398,043	
2. Ending True-Up Amount Before Interest	2,037,677	1,827,433	1,384,775	1,104,652	639,761	615,487	669,425	791,531	873,753	799,847	397,042	(620,186)	
3. Total of Beginning & Ending True-Up (Lines 1 & 2)	4,161,572	3,867,336	3,214,238	2,491,050	1,745,646	1,256,121	1,285,490	1,461,502	1,666,212	1,674,991	1,198,288	(222,143)	
4. Average True-Up Amount (Line 3 x 1/2)	2,080,786	1,933,668	1,607,119	1,245,525	872,823	628,061	642,745	730,751	833,106	837,496	599,144	(111,072)	
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%	2.00%	2.00%	2.00%	2.00%	
6. Interest Rate (First Day of Subsequent Business Month)	1.27%	1.25%	1.18%	1.19%	1.21%	1.00%	1.05%	2.00%	2.00%	2.00%	2.00%	2.00%	
7. Total of Beginning & Ending Interest Rates (Lines 5 & 6)	2.56%	2.52%	2.43%	2.37%	2.40%	2.21%	2.05%	3.05%	4.00%	4.00%	4.00%	4.00%	
8. Average Interest Rate (Line 7 x 1/2)	1.280%	1.260%	1.215%	1.185%	1.200%	1.105%	1.025%	1.525%	2.000%	2.000%	2.000%	2.000%	
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.107%	0.105%	0.101%	0.099%	0.100%	0.092%	0.085%	0.127%	0.167%	0.167%	0.167%	0.167%	
10. Interest Provision for the Month (Line 4 x Line 9)	$2,226	$2,030	$1,623	$1,233	$873	$578	$546	$928	$1,391	$1,399	$1,001	($185)	$13,643

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EXHIBIT NO. _____
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TAMPA ELECTRIC COMPANY
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FORM 42-3E
FILED: AUGUST 8, 2003

Form 42 - 4E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
January 2003 to December 2003

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	$2,123,461	$2,524,200	($400,739)	-15.9%
1b Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
1c SO_2 Emissions Allowances	(389,498)	(132,375)	(257,123)	-194.2%
1d Big Bend Units 1 & 2 FGD	4,844,601	4,448,600	396,001	8.9%
1e Big Bend FGD Optimization and Utilization	(884)	0	(884)	N/A
1f Big Bend PM Minimization and Monitoring	850,167	850,000	167	0.0%
1g Big Bend NO_x Emissions Reduction	250,000	250,000	0	0.0%
1h NPDES Annual Surveillance Fees	43,700	43,700	0	0.0%
1i Gannon Thermal Discharge Study	20,422	216,646	(196,224)	-90.6%
1j Polk NO_x Emissions Reduction	16,400	62,500	(46,100)	-73.8%
1k Bayside SCR Consumables	66,246	0	66,246	N/A
2. Total Investment Projects - Recoverable Costs	$7,824,615	$8,263,271	($438,656)	-5.3%
3. Recoverable Costs Allocated to Energy	$7,760,493	$8,002,925	($242,432)	-3.0%
4. Recoverable Costs Allocated to Demand	$64,122	$260,346	($196,224)	-75.4%

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-02-1735-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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FORM 42-4E
FILED: AUGUST 8, 2003

Form 42 - 5E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated 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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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	$193,731	$187,731	$188,731	$152,731	$158,731	$323,731	$2,123,461		$2,123,461
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)	(53,511)	(62,399)	(58,897)	(28,823)	(17,877)	(19,479)	(389,498)		(389,498)
1d Big Bend Units 1 & 2 FGD (Less Gypsum Revenues)	405,984	236,693	464,857	339,769	453,475	380,073	367,750	351,750	355,750	303,750	338,750	846,000	4,844,601		4,844,601
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	617	8,808	106,621	109,836	60,000	47,000	117,000	117,000	117,000	83,000	850,167		850,167
1g Big Bend NO_x Emissions Reduction	0	0	0	0	0	0	41,667	41,667	41,667	41,667	41,666	41,666	250,000		250,000
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	1,000	1,000	1,000	1,000	1,000	1,000	20,422	20,422	
1j Polk NO_x Emissions Reduction	0	0	0	0	0	0	2,733	2,733	2,733	2,733	2,733	2,735	16,400		16,400
1k Bayside SCR Consumables	0	0	0	0	0	6,246	10,000	10,000	10,000	10,000	10,000	10,000	66,246		66,246
2. Total of O&M Activities	434,711	398,924	502,303	445,577	983,054	658,496	623,370	579,482	657,984	600,058	652,003	1,288,653	7,824,615	64,122	7,760,493
3. Recoverable Costs Allocated to Energy	389,595	398,924	493,180	441,694	983,054	658,496	622,370	578,482	656,984	599,058	651,003	1,287,653	7,760,493		
4. Recoverable Costs Allocated to Demand	45,116	0	9,123	3,883	0	0	1,000	1,000	1,000	1,000	1,000	1,000	64,122		
5. Retail Energy Jurisdictional Factor	0.9696995	0.9728192	0.9585524	0.9678975	0.9667681	0.9696262	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403			
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	638,495	603,028	560,586	641,975	585,843	640,750	1,267,360	7,554,547		
8. Jurisdictional Demand Recoverable Costs (B)	43,057	0	8,707	3,706	0	0	954	954	954	954	954	954	61,194		
9. Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$420,847	$388,081	$481,446	$431,221	$950,385	$638,495	$603,982	$561,540	$642,929	$586,797	$641,704	$1,268,314	$7,615,741		

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

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TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-5E
FILED: AUGUST 8, 2003

Form 42 - 6E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
January 2003 to December 2003

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	$976,427	$984,191	($7,764)	-0.8%
1b	Big Bend Units 1 & 2 Flue Gas Conditioning	603,129	579,498	23,631	4.1%
1c	Big Bend Unit 4 Continuous Emissions Monitors	100,608	100,608	0	0.0%
1d	Gannon Ignition Oil Tank	217,898	108,948	108,950	100.0%
1e	Big Bend Fuel Oil Tank #1 Upgrade	64,133	64,595	(462)	-0.7%
1f	Big Bend Fuel Oil Tank #2 Upgrade	105,465	106,243	(778)	-0.7%
1g	Phillips Upgrade Tank #1 for FDEP	7,604	7,821	(217)	-2.8%
1h	Phillips Upgrade Tank #4 for FDEP	11,965	12,315	(350)	-2.8%
1i	Gannon Unit 5 Classifier Replacement	527,728	280,038	247,690	88.4%
1j	Gannon Unit 6 Classifier Replacement	590,375	324,901	265,474	81.7%
1k	Big Bend Unit 1 Classifier Replacement	181,194	174,989	6,205	3.5%
1l	Big Bend Unit 2 Classifier Replacement	132,558	127,914	4,644	3.6%
1m	Gannon Coal Crusher (NO_x Control)	2,168,390	1,191,334	977,056	82.0%
1n	Big Bend Units 1 & 2 FGD	11,678,268	11,854,274	(176,006)	-1.5%
1o	Big Bend Section 114 Mercury Testing Platform	15,895	15,558	337	2.2%
1p	Big Bend FGD Optimization and Utilization	2,981,723	3,053,015	(71,292)	-2.3%
1q	Big Bend PM Minimization and Monitoring	736,944	772,511	(35,567)	-4.6%
1r	Big Bend NO_x Emissions Reduction	521,571	584,445	(62,874)	-10.8%
1s	Polk NOx Emissions Reduction	141,280	330,291	(189,011)	-57.2%
1t	Big Bend Unit 4 SOFA	85,129	0	85,129	N/A
2.	Total Investment Projects - Recoverable Costs	$21,848,284	$20,673,489	$1,174,795	5.7%
3.	Recoverable Costs Allocated to Energy	$21,441,219	$20,373,567	$1,067,652	5.2%
4.	Recoverable Costs Allocated to Demand	$407,065	$299,922	$107,143	35.7%

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-02-1735-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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FORM 42-6E
FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
January 2003 to December 2003

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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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 Integration	$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 and 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	251,134	250,651	250,168	249,685	249,202	248,718	248,235	247,752	247,269	246,786	246,303	245,820	2,981,723		2,981,723
	1q Big Bend PM Minimization and Monitoring	60,269	61,381	59,560	58,042	59,225	60,187	61,307	61,737	62,070	62,815	64,264	66,087	736,944		736,944
	1r Big Bend NO_x Emissions Reduction	38,565	40,313	41,081	41,757	42,848	43,644	43,949	44,305	44,853	45,733	46,690	47,833	521,571		521,571
	1s Polk NO_x Emissions Reduction	2,510	3,428	5,780	9,834	12,820	13,702	14,439	15,166	15,603	15,918	16,040	16,040	141,280		141,280
	1t Big Bend Unit 4 SOFA	0	0	0	243	532	1,953	5,177	8,392	10,335	12,693	20,080	25,724	85,129		85,129
2.	Total Investment Projects - Recoverable Costs	1,832,884	1,830,374	1,825,381	1,822,547	1,821,805	1,819,576	1,818,672	1,817,112	1,814,084	1,812,087	1,815,713	1,818,049	21,848,284	407,065	21,441,219
3.	Recoverable Costs Allocated to Energy	1,798,779	1,796,303	1,791,343	1,788,542	1,787,834	1,785,637	1,784,767	1,783,240	1,780,243	1,778,282	1,781,941	1,784,308	$21,441,219		
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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403			
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)	1,744,275	1,747,478	1,717,096	1,731,125	1,728,421	1,731,400	1,729,301	1,728,072	1,739,574	1,739,055	1,753,877	1,756,188	20,845,862		
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 Investment Projects (Lines 7 + 8)	$1,776,823	$1,779,994	$1,749,581	$1,763,578	$1,760,842	$1,763,790	$1,761,659	$1,760,398	$1,771,871	$1,771,317	$1,786,108	$1,788,389	$21,234,350		

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. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-7E
FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated 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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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	
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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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	78,750	78,581	79,054	78,935	79,261	79,077	949,283
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	$78,750	$78,581	$79,054	$78,935	$79,261	$79,077	$949,283

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. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
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FORM 42-8E
FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated 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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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)	$5,017,734	$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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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	48,622	48,475	48,725	48,610	48,767	48,611	586,354
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	$48,622	$48,475	$48,725	$48,610	$48,767	$48,611	$586,354

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. 030007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-8E
FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
January 2003 to December 2003

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-03	Actual Feb-03	Actual Mar-03	Actual Apr-03	Actual May-03	Actual Jun-03	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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.	CWIP - Non-Interest Bearing	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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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	8,114	8,097	8,147	8,134	8,168	8,150	97,812
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	$8,114	$8,097	$8,147	$8,134	$8,168	$8,150	$97,812

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

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TAMPA ELECTRIC COMPANY
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FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated 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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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)	(517,118)	(535,276)	(553,434)	(571,593)	(589,752)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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) Applicable 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 February forward, the net investment is zero due to the sum of 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) Asset depreciation was acclerated to achieve full depreciation by year-end 2003. This coincides with commercial operation of Bayside Power Station.
(E) 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)
(F) *Line 9a x Line 10*
(G) Line 9b x Line 11

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DOCKET NO. 030007-EI
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated 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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated 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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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	336	$4,116
	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
	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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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.
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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

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FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$498,692	457,135	415,577	374,019	332,462	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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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	42,416	42,030	41,988	41,627	41,498	41,102	512,989
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	$42,416	$42,030	$41,988	$41,627	$41,498	$41,102	$512,989

Notes:
(A) 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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FORM 42-8E
FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$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		0.9696995	0.9728192	0.9585524	0.9678975	0.9667681	0.9696262	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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)		50,111	49,835	48,671	48,709	48,216	47,921	47,449	47,019	46,971	46,568	46,424	45,994	573,888
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	$47,449	$47,019	$46,971	$46,568	$46,424	$45,994	$573,888

Notes:
(A) 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 acclerated 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

EXHIBIT NO.
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TAMPA ELECTRIC COMPANY
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FORM 42-8E
FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,130,249	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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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	14,609	14,571	14,650	14,620	14,673	14,631	176,154
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	$14,609	$14,571	$14,650	$14,620	$14,673	$14,631	$176,154

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. 030007-EI
TAMPA ELECTRIC COMPANY
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FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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.	CWIP - Non-Interest Bearing	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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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	10,688	10,661	10,720	10,699	10,738	10,709	128,872
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	$10,688	$10,661	$10,720	$10,699	$10,738	$10,709	$128,872

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 Current Period Actual/Estimated Amount
January 2003 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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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	174,281	172,701	172,524	171,042	170,515	168,881	2,107,833
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	$174,281	$172,701	$172,524	$171,042	$170,515	$168,881	$2,107,833

Notes:
(A) 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 acclerated 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. 030007-EI
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FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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	1,282	1,281	1,289	1,287	1,293	1,290	15,453
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	$1,282	$1,281	$1,289	$1,287	$1,293	$1,290	$15,453

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

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DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-8E
FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
January 2003 to December 2003

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-03	Actual Feb-03	Actual Mar-03	Actual Apr-03	Actual May-03	Actual Jun-03	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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	941,577	938,978	944,060	942,058	945,358	942,569	11,353,497
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	$941,577	$938,978	$944,060	$942,058	$945,358	$942,569	$11,353,497

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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)	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	
3.	Less: Accumulated Depreciation	(570,990)	(620,770)	(670,550)	(720,330)	(770,110)	(819,890)	(869,670)	(919,450)	(969,230)	(1,019,010)	(1,068,790)	(1,118,570)	(1,168,350)	
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)	$20,776,176	20,726,396	20,676,616	20,626,836	20,577,056	20,527,276	20,477,496	20,427,716	20,377,936	20,328,156	20,278,376	20,228,596	20,178,816	
6.	Average Net Investment		20,751,286	20,701,506	20,651,726	20,601,946	20,552,166	20,502,386	20,452,606	20,402,826	20,353,046	20,303,266	20,253,486	20,203,706	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		152,588	152,222	151,856	151,490	151,124	150,757	150,391	150,025	149,659	149,293	148,927	148,561	$1,806,893
	b. Debt Component (Line 6 x 2.82% x 1/12)		48,766	48,649	48,532	48,415	48,298	48,181	48,064	47,947	47,830	47,713	47,596	47,479	577,470
8.	Investment Expenses														
	a. Depreciation (D)		49,780	49,780	49,780	49,780	49,780	49,780	49,780	49,780	49,780	49,780	49,780	49,780	597,360
	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)		251,134	250,651	250,168	249,685	249,202	248,718	248,235	247,752	247,269	246,786	246,303	245,820	2,981,723
	a. Recoverable Costs *Allocated to Energy*		251,134	250,651	250,168	249,685	249,202	248,718	248,235	247,752	247,269	246,786	246,303	245,820	2,981,723
	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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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)*		243,525	243,838	239,799	241,669	240,921	241,163	240,520	240,087	241,620	241,342	242,424	241,946	2,898,854
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)		$243,525	$243,838	$239,799	$241,669	$240,921	$241,163	$240,520	$240,087	$241,620	$241,342	$242,424	$241,946	$2,898,854

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated Dec-03	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$70,325	$160,174	($534,200)	$222,861	$22,283	$177,224	$55,000	$35,000	$35,000	$120,000	$180,000	$197,103	$740,770
	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	5,567,380	5,790,241	5,812,524	5,989,748	6,044,748	6,079,748	6,114,748	6,234,748	6,414,748	6,611,851	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$6,106,269	6,175,913	6,335,406	5,800,525	6,022,705	6,044,307	6,220,850	6,275,169	6,309,488	6,343,807	6,463,126	6,642,445	6,838,867	
6.	Average Net Investment		6,141,091	6,255,660	6,067,966	5,911,615	6,033,506	6,132,579	6,248,010	6,292,329	6,326,648	6,403,467	6,552,786	6,740,656	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		45,156	45,999	44,619	43,469	44,365	45,094	45,943	46,269	46,521	47,086	48,184	49,565	$552,270
	b. Debt Component (Line 6 x 2.82% x 1/12)		14,432	14,701	14,260	13,892	14,179	14,412	14,683	14,787	14,868	15,048	15,399	15,841	176,502
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	59,560	58,042	59,225	60,187	61,307	61,737	62,070	62,815	64,264	66,087	736,944
	a. Recoverable Costs Allocated to Energy		60,269	61,381	59,560	58,042	59,225	60,187	61,307	61,737	62,070	62,815	64,264	66,087	736,944
	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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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	57,091	56,179	57,257	58,359	59,402	59,827	60,652	61,429	63,252	65,045	716,649
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	$57,091	$56,179	$57,257	$58,359	$59,402	$59,827	$60,652	$61,429	$63,252	$65,045	$716,649

Notes:
(A) Applicable depreciable base for Big Bend; accounts 315.40 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

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EXHIBIT NO. _____
DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-2)
DOCUMENT NO. 8
PAGE 17 OF 21
FORM 42-8E
FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated Dec-03	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$251,829	$108,497	$49,748	$89,741	$134,967	$29,104	$33,811	$39,657	$73,170	$108,363	$88,679	$146,925	$1,154,491
	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	4,483,341	4,512,445	4,546,256	4,585,913	4,659,083	4,767,446	4,856,125	5,003,050	
5.	Net Investment (Lines 2 + 3 + 4)	$3,848,559	4,100,388	4,208,885	4,258,633	4,348,374	4,483,341	4,512,445	4,546,256	4,585,913	4,659,083	4,767,446	4,856,125	5,003,050	
6.	Average Net Investment		3,974,474	4,154,637	4,233,759	4,303,504	4,415,858	4,497,893	4,529,351	4,566,085	4,622,498	4,713,265	4,811,786	4,929,588	
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	33,305	33,575	33,990	34,657	35,382	36,248	$395,253
	b. Debt Component (Line 6 x 2.82% x 1/12)		9,340	9,763	9,949	10,113	10,377	10,570	10,644	10,730	10,863	11,076	11,308	11,585	126,318
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	43,949	44,305	44,853	45,733	46,690	47,833	521,571
	a. Recoverable Costs Allocated to Energy		38,565	40,313	41,081	41,757	42,848	43,644	43,949	44,305	44,853	45,733	46,690	47,833	521,571
	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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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	42,583	42,934	43,828	44,724	45,955	47,079	507,252
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	$42,583	$42,934	$43,828	$44,724	$45,955	$47,079	$507,252

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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TAMPA ELECTRIC COMPANY
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FORM 42-8E
FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated Dec-03	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$55,175	$134,186	$350,284	$485,350	$130,068	$51,887	$100,000	$50,000	$40,000	$25,000	$0	$0	$1,421,950
	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	1,538,066	1,588,066	1,628,066	1,653,066	1,653,066	1,653,066	
5.	Net Investment (Lines 2 + 3 + 4)	$231,116	286,291	420,477	770,761	1,256,111	1,386,179	1,438,066	1,538,066	1,588,066	1,628,066	1,653,066	1,653,066	1,653,066	
6.	Average Net Investment		258,704	353,384	595,619	1,013,436	1,321,145	1,412,123	1,488,066	1,563,066	1,608,066	1,640,566	1,653,066	1,653,066	
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	10,942	11,493	11,824	12,063	12,155	12,155	$107,063
	b. Debt Component (Line 6 x 2.82% x 1/12)		608	830	1,400	2,382	3,105	3,318	3,497	3,673	3,779	3,855	3,885	3,885	34,217
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	14,439	15,166	15,603	15,918	16,040	16,040	141,280
	a. Recoverable Costs Allocated to Energy		2,510	3,428	5,780	9,834	12,820	13,702	14,439	15,166	15,603	15,918	16,040	16,040	141,280
	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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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)		2,434	3,335	5,540	9,518	12,394	13,286	13,990	14,697	15,247	15,567	15,787	15,787	137,582
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)		$2,434	$3,335	$5,540	$9,518	$12,394	$13,286	$13,990	$14,697	$15,247	$15,567	$15,787	$15,787	$137,582

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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DOCKET NO. 030007-EI
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated Dec-03	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$50,000	$9,611	$283,454	$380,945	$281,739	$118,671	$367,504	$1,155,162	$8,161	$2,655,247
	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	724,010	1,005,749	1,124,420	1,491,924	2,647,086	2,655,247	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	50,000	59,611	343,065	724,010	1,005,749	1,124,420	1,491,924	2,647,086	2,655,247	
6.	Average Net Investment		0	0	0	25,000	54,806	201,338	533,538	864,880	1,065,085	1,308,172	2,069,505	2,651,167	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	184	403	1,480	3,923	6,360	7,832	9,619	15,217	19,494	$64,512
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	59	129	473	1,254	2,032	2,503	3,074	4,863	6,230	20,617
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	5,177	8,392	10,335	12,693	20,080	25,724	85,129
	a. Recoverable Costs Allocated to Energy		0	0	0	243	532	1,953	5,177	8,392	10,335	12,693	20,080	25,724	85,129
	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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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	235	514	1,894	5,016	8,132	10,099	12,413	19,764	25,319	83,386
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	$5,016	$8,132	$10,099	$12,413	$19,764	$25,319	$83,386

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%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

EXHIBIT NO._____
DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-8E
FILED: AUGUST 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
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	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated 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. SO_2 Allowance Expense		(159,799)	(22,333)	(141,032)	(83,796)	288,456	(30,008)	(53,511)	(62,399)	(58,897)	(28,823)	(17,877)	(19,479)	(389,498)
8.	Net Expenses (B)		(159,799)	(22,333)	(141,032)	(83,796)	288,456	(30,008)	(53,511)	(62,399)	(58,897)	(28,823)	(17,877)	(19,479)	(389,498)
9.	Total System Recoverable Expenses (Lines 6 + 7)		(159,799)	(22,333)	(141,032)	(83,796)	288,456	(30,008)	(53,511)	(62,399)	(58,897)	(28,823)	(17,877)	(19,479)	(389,498)
	a. Recoverable Costs Allocated to Energy		(159,799)	(22,333)	(141,032)	(83,796)	288,456	(30,008)	(53,511)	(62,399)	(58,897)	(28,823)	(17,877)	(19,479)	(389,498)
	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	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	
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)		(154,957)	(21,726)	(135,187)	(81,106)	278,870	(29,097)	(51,848)	(60,469)	(57,552)	(28,187)	(17,595)	(19,172)	(378,025)
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)		($154,957)	($21,726)	($135,187)	($81,106)	$278,870	($29,097)	($51,848)	($60,469)	($57,552)	($28,187)	($17,595)	($19,172)	($378,025)

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

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TAMPA ELECTRIC COMPANY
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EXHIBIT NO. _____
DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
FILED: SEPTEMBER 8, 2003

ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2004 THROUGH DECEMBER 2004

42-1P THROUGH 42-7P

EXHIBIT NO._____
DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
FILED: SEPTEMBER 8, 2003

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ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2004 THROUGH DECEMBER 2004

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Form 42 - 1P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2004 to December 2004

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)	$7,911,465	$280,294	$8,191,759
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	17,832,349	175,958	18,008,307
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	25,743,814	456,252	26,200,066
2. True-up for Estimated Over/(Under) Recovery for the current period January 2003 December 2003 (Form 42-2E, Line 5 + 6 + 10)	(161,250)	(2,553)	(163,803)
3. Final True-up for the period January 2002 to December 2002 (Form 42-1A, Line 3)	(450,033)	(6,535)	(456,568)
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2004 to December 2004 (Line 1 - Line 2- Line 3)	26,355,097	465,340	26,820,437
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$26,374,072	$465,675	$26,839,747

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.

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FORM 42-1P
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Form 42-2P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 to December 2004

O & M Activities
(in Dollars)

Line		Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	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	$183,770	$183,770	$183,770	$183,770	$183,770	$183,770	$183,770	$183,770	$183,770	$183,770	$183,770	$184,530	$2,206,000		$2,206,000
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	(17,439)	(13,970)	(13,827)	(15,422)	(20,364)	(20,000)	(20,996)	(21,040)	(20,398)	(18,184)	(17,730)	(20,730)	(220,100)		(220,100)
1d.	Big Bend Units 1 & 2 FGD	329,997	361,827	337,127	336,177	335,227	335,697	334,277	333,327	359,707	356,907	380,007	488,423	4,288,700		4,288,700
1e.	Big Bend FGD Optimization and Utilization	0	0	0	0	0	0	0	0	0	0	0	0	0		0
1f.	Big Bend PM Minimization and Monitoring	82,000	82,000	82,000	82,000	82,000	82,000	82,000	82,000	82,000	82,000	82,000	78,000	980,000		980,000
1g.	Big Bend NO_x Emissions Reduction	45,083	45,083	45,083	45,083	45,083	45,083	45,083	45,083	45,083	45,083	45,083	49,087	545,000		545,000
1h.	Polk NO_x Emissions Reduction	2,733	2,733	2,733	2,733	2,733	2,733	2,733	2,733	2,733	2,733	2,733	2,737	32,800		32,800
1l.	Bayside SCR Consumables	20,250	20,250	20,250	20,250	20,250	20,250	20,250	20,250	20,250	20,250	20,250	20,250	243,000		243,000
1m	Big Bend Unit 4 SOFA	0	0	0	5,555	5,555	5,555	5,555	5,555	5,555	5,555	5,555	5,560	50,000		50,000
	(2) LAND															
	(3) WATER															
3a.	NPDES Annual Surveillance Fees	43,700	0	0	0	0	0	0	0	0	0	0	0	43,700	43,700	
3b.	Gannon Thermal Discharge Study	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,837	250,000	250,000	
2.	*Total of O&M Activities*	$710,927	$702,526	$677,969	$680,979	$675,087	$675,921	$673,505	$672,511	$699,533	$698,947	$722,501	$828,694	$8,419,100	$293,700	$8,125,400
3.	Recoverable Costs Allocated to Energy	646,394	681,693	657,136	660,146	654,254	655,088	652,672	651,678	678,700	678,114	701,668	807,857	8,125,400		
4.	Recoverable Costs Allocated to Demand	64,533	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,833	20,837	293,700		
5.	Energy Jurisdictional Factor	0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444			
6.	*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.	Energy Jurisdictional Recoverable Costs (A)	630,305	664,452	636,362	641,743	633,788	636,980	634,776	633,292	662,420	658,727	686,642	791,978	7,911,465		
8.	Demand Jurisdictional Recoverable Costs (B)	61,588	19,882	19,882	19,882	19,882	19,882	19,882	19,882	19,882	19,882	19,882	19,886	280,294		
9.	Total Jurisdictional Recoverable Costs for O&M *Activities (Lines 7 + 8)*	$691,893	$684,334	$656,244	$661,625	$653,670	$656,862	$654,658	$653,174	$682,302	$678,609	$706,524	$811,864	$8,191,759		

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

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EXHIBIT NO. _____
DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 2
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FORM 42-2P
FILED: SEPTEMBER 8, 2003

Form 42-3P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 to December 2004

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description of Investment Projects (A)	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	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	$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 & 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 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
1e.	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
1f.	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
1g.	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
1h.	Big Bend FGD Optimization and Utilization	245,344	244,861	244,378	243,895	243,412	242,929	242,446	241,963	241,479	240,996	240,513	240,030	2,912,246		2,912,246
1i.	Big Bend PM Minimization and Monitoring	67,839	70,330	73,483	76,121	77,321	77,340	77,333	77,327	77,671	78,818	80,353	81,297	915,233		915,233
1j.	Big Bend NO_x Emissions Reduction	48,569	48,668	48,850	49,102	49,456	49,936	50,519	51,137	51,687	52,080	52,364	52,641	605,009		605,009
1k.	Polk NO_x Emissions Reduction	18,371	20,679	20,633	20,588	20,543	20,497	20,452	20,406	20,361	20,315	20,270	20,224	243,339		243,339
1l.	Big Bend Unit 4 SOFA	26,513	27,995	30,034	34,823	38,271	38,204	38,135	38,068	37,999	37,932	37,864	37,796	423,634		423,634
	(2) LAND															
2b.	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	
2c.	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	
2d.	Phillips Upgrade Tank #1 for FDEP	622	620	619	617	615	614	611	610	608	606	605	603	7,350	7,350	
2e.	Phillips Upgrade Tank #4 for FDEP	979	976	973	971	968	965	963	959	956	954	951	948	11,563	11,563	
2.	Total Investment Projects - Recoverable Costs	$1,541,654	$1,544,252	$1,545,805	$1,549,658	$1,550,836	$1,547,447	$1,544,126	$1,540,847	$1,537,848	$1,535,495	$1,533,425	$1,530,752	$18,502,145	$184,373	$18,317,772
3.	Recoverable Costs Allocated to Energy	1,526,106	1,528,739	1,530,324	1,534,210	1,535,422	1,532,065	1,528,778	1,525,533	1,522,567	1,520,247	1,518,210	1,515,571	18,317,772		
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.	Energy Jurisdictional Factor	0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444			
6.	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.	Energy Jurisdictional Recoverable Costs (B)	1,488,121	1,490,074	1,481,946	1,491,440	1,487,392	1,489,715	1,486,860	1,482,493	1,486,044	1,476,784	1,485,697	1,485,782	17,832,349		
8.	Energy Jurisdictional 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	175,958		
9.	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$1,502,959	$1,504,879	$1,496,721	$1,506,183	$1,502,103	$1,504,395	$1,501,508	$1,497,108	$1,500,628	$1,491,336	$1,500,218	$1,500,270	$18,008,307		

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. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 3
PAGE 1 0F 1
FORM 42-3P
FILED: SEPTEMBER 8, 2003

Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 to December 2004

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-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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	$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)	(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*	*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		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		78,162	77,946	77,261	77,378	76,926	77,034	76,871	76,625	76,777	76,233	76,614	76,570	924,397
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)		$78,162	$77,946	$77,261	$77,378	$76,926	$77,034	$76,871	$76,625	$76,777	$76,233	$76,614	$76,570	$924,397

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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EXHIBIT NO. _____
DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 4
PAGE 1 OF 17
FORM 42-4P
FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 to December 2004

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-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		48,006	47,831	47,368	47,396	47,076	47,099	46,955	46,763	46,812	46,437	46,626	46,553	564,922
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)		$48,006	$47,831	$47,368	$47,396	$47,076	$47,099	$46,955	$46,763	$46,812	$46,437	$46,626	$46,553	$564,922

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. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
DOCUMENT NO. 4
PAGE 2 OF 17
FORM 42-4P
FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		8,055	8,034	7,964	7,975	7,929	7,941	7,924	7,900	7,915	7,859	7,899	7,895	95,290
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)		$8,055	$8,034	$7,964	$7,975	$7,929	$7,941	$7,924	$7,900	$7,915	$7,859	$7,899	$7,895	$95,290

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. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
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FORM 42-4P
FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		14,454	14,406	14,272	14,285	14,195	14,206	14,168	14,115	14,135	14,026	14,089	14,073	170,424
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)		$14,454	$14,406	$14,272	$14,285	$14,195	$14,206	$14,168	$14,115	$14,135	$14,026	$14,089	$14,073	$170,424

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. 030007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-4P
FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		10,580	10,546	10,449	10,459	10,393	10,403	10,375	10,338	10,354	10,275	10,321	10,310	$124,803
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)		$10,580	$10,546	$10,449	$10,459	$10,393	$10,403	$10,375	$10,338	$10,354	$10,275	$10,321	$10,310	$124,803

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. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
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FORM 42-4P
FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 to December 2004

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-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		931,072	927,938	919,186	919,987	914,031	914,719	912,183	908,694	909,891	902,858	906,763	905,625	$10,972,947
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)		$931,072	$927,938	$919,186	$919,987	$914,031	$914,719	$912,183	$908,694	$909,891	$902,858	$906,763	$905,625	$10,972,947

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. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
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FORM 42-4P
FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		1,277	1,274	1,264	1,266	1,259	1,262	1,259	1,257	1,259	1,252	1,258	1,259	$15,146
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)		$1,277	$1,274	$1,264	$1,266	$1,259	$1,262	$1,259	$1,257	$1,259	$1,252	$1,258	$1,259	$15,146

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. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
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FORM 42-4P
FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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)	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	$21,347,166	
3.	Less: Accumulated Depreciation	(1,168,350)	(1,218,137)	(1,267,924)	(1,317,711)	(1,367,498)	(1,417,285)	(1,467,072)	(1,516,859)	(1,566,646)	(1,616,433)	(1,666,220)	(1,716,007)	(1,765,794)	
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)*	$20,178,816	$20,129,029	$20,079,242	$20,029,455	$19,979,668	$19,929,881	$19,880,094	$19,830,307	$19,780,520	$19,730,733	$19,680,946	$19,631,159	$19,581,372	
6.	Average Net Investment		20,153,923	20,104,136	20,054,349	20,004,562	19,954,775	19,904,988	19,855,201	19,805,414	19,755,627	19,705,840	19,656,053	19,606,266	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		148,195	147,829	147,463	147,097	146,731	146,365	145,999	145,633	145,266	144,900	144,534	144,168	$1,754,180
	b. Debt Component (Line 6 x 2.82% x 1/12)		47,362	47,245	47,128	47,011	46,894	46,777	46,660	46,543	46,426	46,309	46,192	46,075	$560,622
8.	Investment Expenses														
	a. *Depreciation (C)*		49,787	49,787	49,787	49,787	49,787	49,787	49,787	49,787	49,787	49,787	49,787	49,787	$597,444
	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)		245,344	244,861	244,378	243,895	243,412	242,929	242,446	241,963	241,479	240,996	240,513	240,030	$2,912,246
	a. Recoverable Costs Allocated to Energy		245,344	244,861	244,378	243,895	243,412	242,929	242,446	241,963	241,479	240,996	240,513	240,030	$2,912,246
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	$0
10.	Energy Jurisdictional Factor		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		239,237	238,668	236,653	237,096	235,798	236,214	235,798	235,136	235,687	234,106	235,362	235,312	$2,835,067
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)		$239,237	$238,668	$236,653	$237,096	$235,798	$236,214	$235,798	$235,136	$235,687	$234,106	$235,362	$235,312	$2,835,067

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

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DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
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PAGE 8 OF 17
FORM 42-4P
FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$165,291	$349,636	$301,515	$243,628	$5,161	$0	$0	$0	$72,545	$165,204	$152,434	$43,608	$1,499,022
	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)	(20,843)	(21,524)	(22,205)	(22,886)	(23,567)	(24,248)	(24,929)	(25,610)	(26,291)	(26,972)	(27,653)	(28,334)	
4.	CWIP - Non-Interest Bearing	6,611,851	6,777,142	7,126,778	7,428,293	7,671,921	7,677,082	7,677,082	7,677,082	7,677,082	7,749,627	7,914,831	8,067,265	8,110,873	
5.	Net Investment (Lines 2 + 3 + 4)	$6,838,867	$7,003,477	$7,352,432	$7,653,266	$7,896,213	$7,900,693	$7,900,012	$7,899,331	$7,898,650	$7,970,514	$8,135,037	$8,286,790	$8,329,717	
6.	Average Net Investment		6,921,172	7,177,955	7,502,849	7,774,740	7,898,453	7,900,353	7,899,672	7,898,991	7,934,582	8,052,776	8,210,914	8,308,254	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		50,893	52,781	55,170	57,169	58,079	58,093	58,088	58,083	58,344	59,213	60,376	61,092	$687,381
	b. Debt Component (Line 6 x 2.82% x 1/12)		16,265	16,868	17,632	18,271	18,561	18,566	18,564	18,563	18,646	18,924	19,296	19,524	$219,680
8.	Investment Expenses														
	a. Depreciation (C)		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)		67,839	70,330	73,483	76,121	77,321	77,340	77,333	77,327	77,671	78,818	80,353	81,297	$915,233
	a. Recoverable Costs Allocated to Energy		67,839	70,330	73,483	76,121	77,321	77,340	77,333	77,327	77,671	78,818	80,353	81,297	$915,233
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	$0
10.	Energy Jurisdictional Factor		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		66,150	68,551	71,160	73,999	74,902	75,202	75,213	75,145	75,808	76,565	78,632	79,699	$891,026
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)		$66,150	$68,551	$71,160	$73,999	$74,902	$75,202	$75,213	$75,145	$75,808	$76,565	$78,632	$79,699	$891,026

Notes:
(A) Applicable depreciable base for Big Bend; accounts 315.40 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. 030007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-4P
FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$4,690	$15,894	$21,664	$30,116	$42,913	$55,985	$64,311	$62,924	$50,412	$30,641	$27,859	$29,272	$436,681
	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	5,003,050	5,007,740	5,023,634	5,045,298	5,075,414	5,118,327	5,174,312	5,238,623	5,301,547	5,351,959	5,382,600	5,410,459	5,439,731	
5.	Net Investment (Lines 2 + 3 + 4)	$5,003,050	$5,007,740	$5,023,634	$5,045,298	$5,075,414	$5,118,327	$5,174,312	$5,238,623	$5,301,547	$5,351,959	$5,382,600	$5,410,459	$5,439,731	
6.	Average Net Investment		5,005,395	5,015,687	5,034,466	5,060,356	5,096,871	5,146,320	5,206,468	5,270,085	5,326,753	5,367,280	5,396,530	5,425,095	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		36,806	36,881	37,019	37,210	37,478	37,842	38,284	38,752	39,169	39,467	39,682	39,892	$458,482
	b. Debt Component (Line 6 x 2.82% x 1/12)		11,763	11,787	11,831	11,892	11,978	12,094	12,235	12,385	12,518	12,613	12,682	12,749	$146,527
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)		48,569	48,668	48,850	49,102	49,456	49,936	50,519	51,137	51,687	52,080	52,364	52,641	$605,009
	a. Recoverable Costs Allocated to Energy		48,569	48,668	48,850	49,102	49,456	49,936	50,519	51,137	51,687	52,080	52,364	52,641	$605,009
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	$0
10.	Energy Jurisdictional Factor		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		47,360	47,437	47,306	47,733	47,909	48,556	49,134	49,694	50,447	50,591	51,243	51,606	$589,016
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)		$47,360	$47,437	$47,306	$47,733	$47,909	$48,556	$49,134	$49,694	$50,447	$50,591	$51,243	$51,606	$589,016

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. 030007-EI
TAMPA ELECTRIC COMPANY
(HTB-3)
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FORM 42-4P
FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	$0
13.	Demand Jurisdictional 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	$59,712
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	$59,712

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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DOCKET NO. 030007-EI
TAMPA ELECTRIC COMPANY
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FORM 42-4P
FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	$0
13.	Demand Jurisdictional Recoverable Costs (E)		8,277	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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TAMPA ELECTRIC COMPANY
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FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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	$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		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	$0
13.	Demand Jurisdictional Recoverable Costs (E)		594	592	591	589	587	586	583	582	580	578	577	575	$7,015
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$594	$592	$591	$589	$587	$586	$583	$582	$580	$578	$577	$575	$7,015

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

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TAMPA ELECTRIC COMPANY
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FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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
															$0
10.	Energy Jurisdictional Factor		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	$0
13.	Demand Jurisdictional 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

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EXHIBIT NO._____
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FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected 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)	$0	$1,653,066	$1,653,066	$1,653,066	$1,653,066	$1,653,066	$1,653,066	$1,653,066	$1,653,066	$1,653,066	$1,653,066	$1,653,066	$1,653,066	
3.	Less: Accumulated Depreciation	0	(2,342)	(7,026)	(11,710)	(16,394)	(21,078)	(25,762)	(30,446)	(35,130)	(39,814)	(44,498)	(49,182)	(53,866)	
4.	CWIP - Non-Interest Bearing	1,653,066	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,653,066	$1,650,724	$1,646,040	$1,641,356	$1,636,672	$1,631,988	$1,627,304	$1,622,620	$1,617,936	$1,613,252	$1,608,568	$1,603,884	$1,599,200	
6.	Average Net Investment		1,651,895	1,648,382	1,643,698	1,639,014	1,634,330	1,629,646	1,624,962	1,620,278	1,615,594	1,610,910	1,606,226	1,601,542	
7.	Return on Average Net Investment														
	a. *Equity Component Grossed Up For Taxes (B)*		12,147	12,121	12,086	12,052	12,018	11,983	11,949	11,914	11,880	11,845	11,811	11,776	$143,582
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,882	3,874	3,863	3,852	3,841	3,830	3,819	3,808	3,797	3,786	3,775	3,764	$45,891
8.	Investment Expenses														
	a. Depreciation (C)		2,342	4,684	4,684	4,684	4,684	4,684	4,684	4,684	4,684	4,684	4,684	4,684	$53,866
	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)		18,371	20,679	20,633	20,588	20,543	20,497	20,452	20,406	20,361	20,315	20,270	20,224	$243,339
	a. Recoverable Costs Allocated to Energy		18,371	20,679	20,633	20,588	20,543	20,497	20,452	20,406	20,361	20,315	20,270	20,224	$243,339
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	$0
10.	*Energy Jurisdictional Factor*		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		17,914	20,156	19,981	20,014	19,900	19,930	19,891	19,830	19,873	19,734	19,836	19,826	$236,885
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)		$17,914	$20,156	$19,981	$20,014	$19,900	$19,930	$19,891	$19,830	$19,873	$19,734	$19,836	$19,826	$236,885

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. 030007-EI
TAMPA ELECTRIC COMPANY
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FILED: SEPTEMBER 8, 2003

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$154,304	$151,084	$269,365	$0	$0	$0	$0	$0	$0	$0	$0	$0	$574,753
	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	$3,230,000	$3,230,000	$3,230,000	$3,230,000	$3,230,000	$3,230,000	$3,230,000	$3,230,000	$3,230,000	
3.	Less: Accumulated Depreciation	0	0	0	0	(3,499)	(10,497)	(17,495)	(24,493)	(31,491)	(38,489)	(45,487)	(52,485)	(59,483)	
4.	CWIP - Non-Interest Bearing	2,655,247	2,809,551	2,960,635	3,230,000	0	0	0	0	0	0	0	0	0	
5.	Net Investment (*Lines 2 + 3 + 4*)	$2,655,247	$2,809,551	$2,960,635	$3,230,000	$3,226,501	$3,219,503	$3,212,505	$3,205,507	$3,198,509	$3,191,511	$3,184,513	$3,177,515	$3,170,517	
6.	Average Net Investment		2,732,399	2,885,093	3,095,318	3,228,251	3,223,002	3,216,004	3,209,006	3,202,008	3,195,010	3,188,012	3,181,014	3,174,016	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		20,092	21,215	22,760	23,738	23,699	23,648	23,596	23,545	23,493	23,442	23,391	23,339	$275,958
	b. Debt Component (Line 6 x 2.82% x 1/12)		6,421	6,780	7,274	7,586	7,574	7,558	7,541	7,525	7,508	7,492	7,475	7,459	$88,193
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	3,499	6,998	6,998	6,998	6,998	6,998	6,998	6,998	6,998	$59,483
	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)		26,513	27,995	30,034	34,823	38,271	38,204	38,135	38,068	37,999	37,932	37,864	37,796	$423,634
	a. Recoverable Costs Allocated to Energy		26,513	27,995	30,034	34,823	38,271	38,204	38,135	38,068	37,999	37,932	37,864	37,796	$423,634
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	$0
10.	Energy Jurisdictional Factor		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (D)		25,853	27,287	29,085	33,852	37,074	37,148	37,089	36,994	37,087	36,848	37,053	37,053	$412,423
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)		$25,853	$27,287	$29,085	$33,852	$37,074	$37,148	$37,089	$36,994	$37,087	$36,848	$37,053	$37,053	$412,423

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2004 to December 2004

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-04	Projected Feb-04	Projected Mar-04	Projected Apr-04	Projected May-04	Projected Jun-04	Projected Jul-04	Projected Aug-04	Projected Sep-04	Projected Oct-04	Projected Nov-04	Projected Dec-04	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		(17,439)	(13,970)	(13,827)	(15,422)	(20,364)	(20,000)	(20,996)	(21,040)	(20,398)	(18,184)	(17,730)	(20,730)	(220,100)
8.	Net Expenses (E)		(17,439)	(13,970)	(13,827)	(15,422)	(20,364)	(20,000)	(20,996)	(21,040)	(20,398)	(18,184)	(17,730)	(20,730)	(220,100)
9.	Total System Recoverable Expenses (Lines 6 + 7)		(17,439)	(13,970)	(13,827)	(15,422)	(20,364)	(20,000)	(20,996)	(21,040)	(20,398)	(18,184)	(17,730)	(20,730)	(220,100)
	a. Recoverable Costs Allocated to Energy		(17,439)	(13,970)	(13,827)	(15,422)	(20,364)	(20,000)	(20,996)	(21,040)	(20,398)	(18,184)	(17,730)	(20,730)	(220,100)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
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.	Energy Jurisdictional Recoverable Costs (B)		(17,005)	(13,617)	(13,390)	(14,992)	(19,727)	(19,447)	(20,420)	(20,446)	(19,909)	(17,664)	(17,350)	(20,323)	(214,290)
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)		($17,005)	($13,617)	($13,390)	($14,992)	($19,727)	($19,447)	($20,420)	($20,446)	($19,909)	($17,664)	($17,350)	($20,323)	($214,290)

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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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 2003 through December 2003 is $976,427 compared to the original projection of $984,191 representing a variance of –0.8%. This variance resulted from the application of a new depreciation rate preliminarily approved in Docket No. 030409-EI, Order No. PSC-03-0736-PCO-EI, issued June 20, 2003.

The actual/estimated O&M expense for the period January 2003 through December 2003 is $2,123,461 compared to the original projection of $2,524,200 representing a variance of –15.9%. This variance resulted primarily from the decreased cost of reagents.

Project Progress Summary: The project is complete and in service.

Project Projections: Estimated depreciation plus return for the period January 2004 through December 2004 is expected to be $949,565.

Estimated O&M costs for the period January 2004 through December 2004 are projected to be $2,206,000.

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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 2003 through December 2003 is $603,129 compared to the original projection of $579,498 representing a variance of 4.1%. This variance resulted from the application of a new depreciation rate preliminarily approved in Docket No. 030409-EI, Order No. PSC-03-0736-PCO-EI, issued June 20, 2003.

The actual/estimated O&M expense for this project for the period January 2003 through December 2003 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 2004 through December 2004 is projected to be $580,305.

Estimated O&M costs for the period January 2004 through December 2004 are projected to be $0.

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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 2003 through December 2003 is $100,608 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 2004 through December 2004 is projected to be $97,884.

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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 2003 through December 2003 is $181,194 compared to the original projection of $174,989 representing a variance of 3.5%. This variance resulted from the application of a new depreciation rate preliminarily approved in Docket No. 030409-EI, Order No. PSC-03-0736-PCO-EI, issued June 20, 2003.

Progress Summary: The project is complete and was placed in service December 1998.

Project Projections: Estimated depreciation plus return for the period January 2004 through December 2004 is projected to be $175,064.

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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 2003 through December 2003 is $132,558 compared to the original projection of $127,914 representing a variance of 3.6%. This variance resulted from the application of a new depreciation rate preliminarily approved in Docket No. 030409-EI, Order No. PSC-03-0736-PCO-EI, issued June 20, 2003.

Progress Summary: The project is complete and was placed in service May 1998.

Project Projections: Estimated depreciation plus return for the period January 2004 through December 2004 is projected to be $128,202.

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Project Title: Gannon Unit 5 Classifier Replacement

Project Description:

The boiler modifications at Gannon Unit 5 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 2003 through December 2003 is $527,728 compared to the original projection of $280,038 representing a variance of 88.4%. This variance resulted from the accelerated depreciation of Gannon Station assets in conjunction with the early start-up of Bayside Units 1 & 2.
Progress Summary:	The project is complete and was placed in service December 1997.
Project Projections:	No expenditures are anticipated in 2004. The project will be fully depreciated by year-end 2003.

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Project Title: Gannon Unit 6 Classifier Replacement

Project Description:

The boiler modifications at Gannon Unit 6 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 2003 through December 2003 is $590,375 compared to the original projection of $324,901 representing a variance of 81.7%. This variance resulted from the accelerated depreciation of Gannon Station assets in conjunction with the early start-up of Bayside Units 1 & 2.
Progress Summary:	The project is complete and was placed in service July 1999.
Project Projections:	No expenditures are anticipated in 2004. The project will be fully depreciated by year-end 2003.

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Project Title: Gannon Coal Crushers (NO_x Control)

Project Description:

Two Gannon coal crushers will be used in conjunction with the boiler modifications at Gannon as part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The coal crushers will assist in achieving compliance by providing a more uniform particle size. The finer coal particles, 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 2003 through December 2003 is $2,168,390 compared to the original projection of $1,191,334 representing a variance of 82.0%. This variance resulted from the accelerated depreciation of Gannon Station assets in conjunction with the early start-up of Bayside Units 1 & 2.

Progress Summary: The project is complete and was placed in service June 1999.

Project Projections: No expenditures are anticipated in 2004. The project will be fully depreciated by year-end 2003.

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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 2003 through December 2003 is $11,678,268 compared to the original projection of $11,854,274 representing a variance of -1.5%. This variance resulted from the application of a new depreciation rate preliminarily approved in Docket No. 030409-EI, Order No. PSC-03-0736-PCO-EI, issued June 20, 2003.

The actual/estimated O&M expense for the period January 2003 through December 2003 is $4,844,601 as compared to the original estimate of $4,448,600 resulting in a variance of 8.9%. This variance resulted primarily from additional contractor maintenance costs than originally projected.

Project Progress Summary: The project was placed in service in December 1999.

Project Projections: Estimated depreciation plus return for the period January 2004 through December 2004 is expected to be $11,271,732.

Estimated O&M costs for the period January 2004 through December 2004 are projected to be $4,288,700.

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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 2003 through December 2003 is $15,895 compared to the original projection of $15,558 representing a variance of 2.2%. This variance resulted from the application of a new depreciation rate preliminarily approved in Docket No. 030409-EI, Order No. PSC-03-0736-PCO-EI, issued June 20, 2003.
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 2004 through December 2004 is expected to be $15,559.

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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 2003 through December 2003 is $2,981,723 as compared to the original projection of $3,053,015 resulting in a variance of -2.3%. This variance resulted from the application of a new depreciation rate preliminarily approved in Docket No. 030409-EI, Order No. PSC-03-0736-PCO-EI, issued June 20, 2003.

The actual/estimated O & M expense for this project for the period January 2003 through December 2003 is ($884) as compared to the original projection of $0. This variance was due to the correction of a previous period's invoice inadvertently charged to the wrong account.

Project Progress Summary: The project was placed in service in January 2002.

Project Projections: Estimated depreciation plus return for the period January 2004 through December 2004 is expected to be $2,912,246.

Estimated O&M costs for the period January 2004 through December 2004 are projected to be $0.

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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 2003 through December 2003 is $736,944 as compared to the original projection of $772,511 resulting in a variance of -4.6%. This variance was primarily due to a change in the scheduling of unit outages. The work will occur later in the year.

The actual/estimated O&M expense the period January 2003 through December 2003 is $850,167 as compared to the original projection of $850,000 resulting in an insignificant variance of $167.

Project Progress Summary: The project is an ongoing compliance activity.

Project Projections: Estimated depreciation plus return for the period January 2004 through December 2004 is expected to be $915,233.

Estimated O&M costs for the period January 2004 through December 2004 are projected to be $980,000.

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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 2003 through December 2003 is $521,571 as compared to the original projection of $584,445 resulting in a variance of -10.8%. This variance was primarily due to a change in the scheduling of unit outages. Also, lower than anticipated contractor costs have occurred.

The actual/estimated O&M expense for the period January 2003 through December 2003 is $250,000 and did not vary from the original projection.

Project Progress Summary: The project is an ongoing compliance activity.

Project Projections: Estimated depreciation plus return for the period January 2004 through December 2004 is expected to be $605,009.

Estimated O&M costs for the period January 2004 through December 2004 are projected to be $545,000.

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Project Title: *Gannon Ignition Oil Tank*

Project Description:

The Gannon Ignition Oil Tank is a 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 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 2003 through December 2003 was $217,898 compared to the original projection of $108,948 representing a variance of 100.0%. This variance resulted from the accelerated depreciation of Gannon Station assets in conjunction with the early start-up of Bayside Units 1 & 2.
Project Progress Summary:	The project is complete and was placed in service January 1998.
Project Projections:	No expenditures are anticipated in 2004. The project will be fully depreciated by year-end 2003.

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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 2003 through December 2003 is $64,133 compared to the original projection of $64,595 representing a variance of –0.7%. This variance resulted from the application of a new depreciation rate preliminarily approved in Docket No. 030409-EI, Order No. PSC-03-0736-PCO-EI, issued June 20, 2003.
Project Progress Summary:	The project is complete and was placed in service October 1998.
Project Projections:	Estimated depreciation plus return for the period January 2004 through December 2004 is projected to be $62,567.

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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 2003 through December 2003 is $105,465 compared to the original projection of $106,243 representing a variance of –0.7%. This variance resulted from the application of a new depreciation rate preliminarily approved in Docket No. 030409-EI, Order No. PSC-03-0736-PCO-EI, issued June 20, 2003.
Project Progress Summary:	The project is complete and was placed in service December 1998.
Project Projections:	Estimated depreciation plus return for the period January 2004 through December 2004 is projected to be $102,893.

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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 2003 through December 2003 is $7,604 compared to the original projection of $7,821 representing a variance of –2.8%. This variance resulted from the application of a new depreciation rate preliminarily approved in Docket No. 030409-EI, Order No. PSC-03-0736-PCO-EI, issued June 20, 2003.
Project Progress Summary:	The project is complete and was placed in service October 1998.
Project Projections:	Estimated depreciation plus return for the period January 2004 through December 2004 is projected to be $7,350.

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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 2003 through December 2003 is $11,965 compared to the original projection of $12,315 representing a variance of –2.8%. This variance resulted from the application of a new depreciation rate preliminarily approved in Docket No. 030409-EI, Order No. PSC-03-0736-PCO-EI, issued June 20, 2003.
Project Progress Summary:	The project is complete and was placed in service October 1998.
Project Projections:	Estimated depreciation plus return for the period January 2004 through December 2004 is projected to be $11,563.

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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 2003 through December 2003 is ($389,498) compared to the original projection of ($132,375) representing a variance of –194.2%. This variance was due to the unanticipated proceeds from the sale of allowances which created a credit balance that was 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 2004 through December 2004 are projected to be ($220,100).

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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 2003 through December 2003 is $43,700 and did not vary from the original projection.
Project Summary:	NPDES Surveillance fees are paid annually for the prior year.
Project Projections:	Estimated O&M costs for the period January 2004 through December 2004 are projected to be $43,700.

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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 2003.

Project Accomplishments:

Project Fiscal Expenditures:	The actual/estimated O&M expense for the period January 2003 through December 2003 is $20,422 compared to the original projection of $216,646 which represents a variance of –90.6%. This variance is primarily due to a delay in the commencement of the sampling plan. The delay stems from ongoing negotiations with the FDEP related to the extent of sampling necessary.
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 and will continue through 2004.
Project Projections:	Estimated O&M costs for the period January 2004 through December 2004 are projected to be $250,000.

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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, 2003. 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 2003 through December 2003 is $141,280 as compared to the original projection of $330,291 resulting in a variance of –57.2%. This variance was due to the attainment of the NO_x emissions limit without the expenditure associated with the originally planned modifications to the main air compressor.

The actual/estimated O&M for the period January 2003 through December 2003 is $16,400 compared to the original projection of $62,500 which represents a variance of -73.8%. This variance was due to the limited amount of expense estimated to occur for the balance of 2003 based on the newness of equipment and a greater familiarity with operations subsequent to equipment start-up and initial testing.

Project Summary: This project was approved by the Commission in Docket No. 020726-EI, Order No. PSC-02-1445-PAA-EI, issued October 21, 2002. Final invoices from the contractors are being submitted and the project will then be placed in-service.

Project Projections: Estimated depreciation plus return for the period January 2004 through December 2004 is projected to be $243,339.

Estimated O&M costs for the period January 2004 through December 2004 are projected to be $32,800.

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Tampa Electric Company
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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 2003 through December 2003 is $66,246 compared to the original projection of $0. This variance was due to project approval occurring subsequent to the filing date for the 2003 ECRC Projection Filing.
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. Expenses will occur sooner than anticipated in the original petition for program approval due to the early start-up of Bayside Units 1 & 2.
Project Projections:	Estimated O&M costs for the period January 2004 through December 2004 are projected to be $243,000.

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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 2003 through December 2003 is $85,129 compared to the original projection of $0. This variance was due to project approval occurring subsequent to the filing date for the 2003 ECRC Projection Filing.

There is no actual/estimated O&M expense for the period January 2003 through December 2003.

Project Summary: This project was approved by the Commission in Docket No. 030226-EI, Order No. PSC-03-0684-PAA-EI, issued June 6, 2003. Equipment installation is underway and system functionally is expected in early 2004.

Project Projections: Estimated depreciation plus return for the period January 2004 through December 2004 is projected to be $423,634.

Estimated O&M costs for the period January 2004 through December 2004 are projected to be $50,000.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2004 to December 2004

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	57.72%	8,393,405,000	1,659,999	1.06028	1.04917	8,806,108,724	1,760,064	44.91%	56.07%	55.21%
GS, GST, TS	63.59%	1,070,071,000	192,097	1.06028	1.04917	1,122,686,391	203,677	5.72%	6.49%	6.43%
GSD, GSDT	74.67%	5,221,207,000	798,216	1.05875	1.04848	5,474,331,115	845,111	27.92%	26.92%	26.99%
GSLD, GSLDT, SBF, SBFT	84.60%	2,233,911,000	301,433	1.04616	1.03740	2,317,459,271	315,347	11.82%	10.05%	10.19%
IS1, IST1, SBI1, SBIT1, IS3, IST3, SBI3,SBIT3	98.45%	1,647,561,000	0	1.02147	1.01796	1,677,151,196	0	8.55%	0.00%	0.66%
SL/OL	163.91%	202,731,000	14,119	1.06028	1.04917	212,699,283	14,970	1.08%	0.48%	0.52%
TOTAL		18,768,886,000	2,965,864			19,610,435,980	3,139,169	100.00%	100.00%	100.00%

Notes: (1) Average 12 CP load factor based on actual 2001 load research data
(2) Projected kWh sales for the period January 2004 to December 2004
(3) Calculated: (Column 2) / (8,760 hours x Column 1)
(4) Based on actual 2001 load research data
(5) Based on actual 2001 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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2004 to December 2004

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	44.91%	55.21%	11,844,596	257,099	12,101,695	8,393,405,000	**0.144**
GS, GST, TS	5.72%	6.43%	1,508,597	29,943	1,538,540	1,070,071,000	**0.144**
GSD, GSDT	27.92%	26.99%	7,363,641	125,686	7,489,327	5,221,207,000	**0.143**
GSLD, GSLDT, SBF, SBFT	11.82%	10.19%	3,117,415	47,452	3,164,867	2,233,911,000	**0.142**
IS1, IST1, SBI1, SBIT1, IS3, IST3, SBI3,SBIT3	8.55%	0.66%	2,254,983	3,073	2,258,056	1,647,561,000	**0.137**
SL/OL	1.08%	0.52%	284,840	2,422	287,262	202,731,000	**0.142**
TOTAL	100.00%	100.00%	26,374,072	465,675	26,839,747	18,768,886,000	**0.143**

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

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BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition of Progress Energy Floirda, Inc. for approval of new environmental programs for cost recovery through environmental cost recovery clause.	Docket No. 030711-EI Dated: September 5, 2003

PROGRESS ENERGY FLORIDA'S ANSWERS TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-13)

Progress Energy Florida, Inc., ("PEF" or "Company"), pursuant to Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staff's First Set of Interrogatories (Nos. 1-13) in the above docket.

1. **Rule 62-761.510, Florida Administrative code, was adopted in 1990, and amended in 1992, 1996, and 1998. Please explain how the compliance requirements for aboveground storage tanks and associated pipelines (ASTs) changed with each amendment.**

Response:
Rule 62-761.510, F.A.C. became legally effective on December 10, 1990. At that time, that rule section only addressed performance standards for existing underground vehicular fuel petroleum storage tank systems. Subsequently, on March 12, 1991, aboveground storage tank (AST) rules contained in Chapter 17-762, F.A.C. became legally effective. With respect to the secondary containment requirements for ASTs and AST integral piping, Chapter 17-762 required that new shop-fabricated and field-erected storage tank systems (including integral piping in contact with soil associated with new ASTs) have impervious secondary containment installed as part of such storage tanks and piping at the time of construction. A copy of that 1991 rule section and the specific secondary requirements for new ASTs and their integral piping constructed after March 12, 1991 (Rule 17-762.500(4),(6), F.A.C.) is provided as Attachment 1-1.

Some

Field-erected and certain shop-fabricated ASTs existing on March 12, 1991 were required to meet the secondary containment requirements for new ASTs found in Rule 17-762.500 (6), F.A.C. by December 31, 1999. For example, certain shop-fabricated ASTs existing on March 12, 1991 were required to be upgraded to meet the secondary containment requirements in Rule 17-762.500(6), F.A.C. underneath such ASTs by December 31, 1999. In lieu of installing secondary containment underneath an existing shop-fabricated AST, the interior bottom of the AST and at least 18 inches up the sides could be coated with an epoxy coating or other suitable material. A copy of former rule 17-762.510, F.A.C. that contains the secondary containment requirements for existing shop-fabricated ASTs is provided as Attachment 1-2.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030607-EI EXHIBIT NO. Comp. Ex. 5
COMPANY/ Progress Energy Responses
WITNESS: to Staff's Interrogatories
DATE: 11-12-03

Field-erected ASTs existing on March 12, 1991 were to meet the secondary containment requirements in Rule 17-762.500(6), F.A.C. also by December 31, 1999. In lieu of installing secondary containment underneath an existing field-erected AST, the interior bottom of the tank and at least 18 inches up the sides could be coated with an epoxy coating or other suitable material. A copy of former rule 17-762.520, F.A.C. that contains the secondary containment requirements for existing field-erected ASTs is provided as Attachment 1-3.

Integral piping in contact with soil, associated with both existing shop-fabricated and field-erected ASTs, was to be upgraded with secondary containment according to the standards of former Rule 17-762.500(4), F.A.C. by December 31, 1999, except for hydrant piping and bulk product piping associated with existing field-erected ASTs. See, Rules 17-762.510(3) and 17-762.520(2)(a), F.A.C. found in Attachments 1-2 and 1-3, respectively. A copy of former Rule 17-762.500(4), F.A.C. is also provided in Attachment 1-1. Hydrant piping and bulk product piping associated with existing field-erected ASTs were required to meet alternative requirements set forth in former Rule 17-762.520(2)(b), F.A.C. A copy of that rule section is also provided in Attachment 1-3.

In 1994, the provisions of Chapter 17-762, F.A.C. were transferred and renumbered with no substantive change to new Chapter 62-762, F.A.C. This included the provisions of former Rules17-762.500, 17-762.510, and 17-762.520, F.A.C. which were renumbered Rules 62-762.500, 62-762.510, and 62-762.520, F.A.C., respectively. Subsequently in 1996, additional amendments were made to Chapter 62-762, F.A.C. with no substantive change to the AST and associated integral piping secondary containment requirements found in Rules 62-762.500, 62-762.510, and 62-762.520, F.A.C.

In 1998, FDEP adopted significant revisions to both the underground storage tank (UST) (at that time found at Chapter 62-761, F.A.C.) and AST rules. Those rule amendments consolidated the UST and AST rules into a reformatted and reorganized Chapter 62-761, F.A.C. entitled "Underground Storage Tank Systems". During that rulemaking effort, FDEP amended existing Rule 62-761.510, F.A.C. setting out performance standards for both existing USTs and ASTs. The rulemaking resulted in additional secondary containment requirements for shop-fabricated and field-erected ASTs existing as of July 13, 1998, as well as integral piping associated with such ASTs.

In relation to shop-fabricated ASTs, the rule changes created new performance standards for secondary containment comprised of either concrete or synthetic liners already constructed under and around such ASTs that were to be met no later than January 1, 2000. For field-erected ASTs, these new performance standards are to be met no later than January 1, 2005. As well, new secondary containment requirements for single bottom ASTs (both shop-fabricated and field-erected) that were internally lined in accordance with prior FDEP standards are now to be upgraded with secondary containment by January 1, 2010. Finally, certain integral piping in contact with soil, specifically bulk product is required to be upgraded with secondary containment also

by January 1, 2010. The 1998 rule changes are found in current Rule 62-761.510, F.A.C. which was attached as Exhibit B to Progress Energy Florida's petition filed on July 28, 2003.

2. **For each AST subject to Rule 62-761.510, please provide the following information: the in-service date, the location, initial plant-in-service amount with account name and number, current accumulated depreciation with the account name and number, current net plant in service balance, the substance stored in the AST.**

Response:
See Attachments 2-1

3. **For each AST subject to Rule 62-761.510, please itemize all maintenance to the AST within the past 10 years. For each maintenance activity on each tank, please provide the following information: a description of each maintenance activity; the date the cost was incurred; the cost; the account name and number in which the cost was recorded; whether the cost was expense or capitalized; whether the activity was conducted to comply with an environmental law or regulation, as defined in Section 366.8255(1)(c), Florida Statutes. If the activity was conducted to comply with such an environmental law or regulation, please provide a citation for the law or regulation with as much specificity as possible, and provide the compliance deadline with a citation for that deadline.**

Response:
See Attachment 3-1.

4. **Paragraph 20 of the Petition is headed "2004 Cost Estimates", but states that no costs will be incurred in 2005. Was the intent to say that no costs will be incurred in 2004?**

Response:
Yes. The reference to 2005 was a typographical error.

5. **The FDEP Storage Tank Compliance Verification Program maintains several databases of regulated facilities. It shows that Progress Energy has single-walled ASTs that are potentially subject to Rule 62-761.510. Those ASTs are:**

Crystal River	**4**	**Higgins**	**1**
Monticello Garage	**1**	**Jamestown Ops. Ctr.**	**2**
Anclote	**2**	**Suwanee**	**3**
Bartow	**1**	**DeBary**	**1**
Bayboro	**1**	**Turner**	**1**

A. **Please explain why progress does not propose any work on each of these facilities.**

B. **The list does not include the ASTs and Intercession City, University of Florida, Avon and Rio Pinar. Please explain, in detail, why these four sites are subject to Rule 62-761.510, and provide citations to the relevant parts of the rule.**

Response:
The FDEP Regulated Facilities/Tank Inventory has not updated to reflect changes of status of ASTs that have been reported since May 2001. Please see Attachments 5-1 and 5-2 for specific detail regarding the work at the various sites, and the applicable regulatory citation. Attachment 5-1 includes work that has not been completed and which is included in the PEF's petition. Attachment 5-2 includes work that has already been completed and, therefore, is not included in PEF's Petition.

6. **For each AST subject to Rule 62-761.510, please provide the schedule of work to be conducted on the AST required by the rule. The schedule should show the beginning and completion dates for each such activity.**

Response:
See Attachments 5-1 and 5-2.

7. **If Progress Energy does not expect to achieve compliance with Rule 62-761.510 by December 31, 2009, please provide the reasons.**

Response:
Progress Energy will comply with Rule 62-761.510 by December 31, 2009.

8. **Please explain why Progress believes the AST activities must be performed during scheduled outages or off-peak periods.**

Response:
It has always been PEF's objective to maximize maintenance activities during unit outages or off-peak period. This practice is intended to minimize the replacement fuel costs that would result if maintenance were performed during period when the unit is needed to meet customer demand.

9. **When did Progress first become aware of a DEP rule requiring additional environmental protection on ASTs?**

Response:
PEF became aware of the requirements addressed in its Petition when the current version of Rule 62-762.510 was adopted in July, 1998. As explained in the Petition, however, the rule contained delayed compliance dates.

10. **The requirements for complying with Rule 62-761.510 (3) (d) may vary for each AST depending on the type of existing facilities, the material transported in the pipes, whether the pipes are in contact with the soil, and many other factors. For each AST subject to the rule, please explain the work that must be done on the AST to comply with the rule and provide citation to the provisions of the rule that requires the work. If you cannot answer this question completely for each tank, please provide the information you do have.**

Response:
See Attachments 5-1 and 5-2.

11. **Please explain how hiring an outside consultant to do some of the work required by Rule 62-761.510 ensures that the expenditures are prudent.**

Response:
Analysis of the work to be performed resulted in the decision to hire an outside consultant because internal expertise to complete the job is not available.

12. **When did Progress first become aware that the US. DOT Regulation 49 CFR Part 195 affected any of its oil pipelines, and what is the first year in which Progress could have budgeted compliance costs?**

Response:
PEF became aware of the final rule when it was published in the *Federal Register* on January 16, 2002. The first year compliance costs were budgeted was 2003.

13. **On What date did Progress Energy complete the MFR budget referenced in paragraphs 9 and 18 of the Petition?**

Response:
PEF completed the MFR budget for 2002 in July 2001.

SERVED this 5th day of September, 2003.

Richard D. Melson
Gary V. Perko
HOPPING GREEN & SAMS, P.A.
123 South Calhoun Street
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Florida Power Corporation

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared Patricia Q. West, who

(X) is personally known to me, or

( ) produced _____ as identification

and who, being duly sworn, deposes and says that the foregoing answers to interrogatories Nos. 1, 5, 6, 7, 9, 10, 11, and 12 are true and correct to the best of his/her knowledge, information and belief.

June C. Lamb
Commission # CC 959120
Expires Sep. 18, 2004
Bonded Thru
Atlantic Bonding Co., Inc.

June C. Lamb
Notary Public
State of Florida

My commission Expires:
Sep. 18, 2004

AFFIDAVIT

STATE OF FL)
)
COUNTY OF Pinellas)

Before me, the undersigned authority, personally appeared Javier Portuondo, who

(X) is personally known to me, or

( ) produced _____ as identification

and who, being duly sworn, deposes and says that the foregoing answers to interrogatories Nos. 2, 3, 4, 8, 13 are true and correct to the best of his/her knowledge, information and belief.

Javier Portuondo

Notary Public
State of FL

My commission Expires:

SANDRA CAROL COPE
Notary Public - State of Florida
My Commission Expires Mar 8, 2006
Commission # DD 098038
Bonded By National Notary Assn.

Sandra Cope 9/3/03

the positive response is the result of a prior known release. A positive response shall include, but is not limited to, failure of a tightness test, failure of a pressure test on piping containing pollutants, a sheen or layer of petroleum product or odors of pollutants in a ground water sample, a sheen or layer of petroleum product on surface water, an exceedance of ground or surface water standards for the pollutant stored, or vapor levels in excess of those allowed by Rule 17-761.640(2)(e), 1., 2., 4., or 5., F.A.C.

Specific Authority 376.303 FS. Law Implemented 376.303 FS. History—New 3-12-91.

17-762.480 Financial Responsibility.

(1) The owner or operator of a storage tank system shall demonstrate to the Department the ability to pay for facility cleanup and third-party liability resulting from a discharge at any facility. Except for the coverage limits specified in this subsection, the minimum requirements for financial responsibility shall be the same minimum requirements provided by the Code of Federal Regulations, Title 40, Part 280, Subpart H for underground storage tanks and shall be made by January 1, 1995.

(a) Owners or operators of a storage tank system with a capacity of 250,000 gallons or less shall demonstrate financial responsibility for facility cleanup and third-party liability to a minimum of $1 million per incident and $2 million annual aggregate.

(b) Owners or operators of a storage tank system with a capacity greater than 250,000 gallons shall demonstrate financial responsibility for facility cleanup and third-party liability to a minimum of $3 million per incident and $6 million annual aggregate.

(2) Financial responsibility for owners or operators of petroleum product storage systems may be met or supplemented by participation in the Florida Petroleum Liability Insurance and Restoration Program in accordance with Rule 17-769, F.A.C.

(3) Notwithstanding the owner's or operator's financial responsibility status, the owner or operator may, in accordance with Chapter 376 and 403, F.S., be liable for any discharge at the facility.

Specific Authority 376.303, 376.309 FS. Law Implemented 376.303, 376.309 FS. History—New 3-12-91.

17-762.500 Performance Standards for New Storage Tank Systems. All owners or operators of new storage tank systems shall comply with the requirements of this section.

(1) New aboveground storage systems with capacities of more than 550 gallons that contain pollutants shall meet the requirements of this section at the time of construction. New or replacement field-erected tanks constructed within an existing common containment area containing existing field-erected tanks shall meet the requirements of subsection (6) of this section by December 31, 1999. Secondary containment shall be installed beneath the tank.

(2) New storage tank systems shall be made of or lined with materials that are compatible with the pollutant stored in the system.

(3) Tanks. All new tanks installed at a facility shall meet the following standards:

(a) New aboveground storage tanks constructed of steel shall meet or exceed the requirements found in UL No. 142, API Standard No. 620, API Standard No. 650, API Standard No. 12B, API Standard No. 12D or API Standard No. 12F. Fiberglass reinforced plastic tanks shall meet or exceed the requirements found in API Specification 12P. Any aboveground tank constructed of other materials shall not be installed unless such materials have been approved by the Department pursuant to Rule 17-762.860, F.A.C. All rotationally-molded polyethylene tanks used for the storage of pollutants other than petroleum products are approved provided they are installed in accordance with manufacturers specifications, meet corrosion compatibility requirements (as indicated by the manufacturer), and have secondary containment in accordance with Rule 17-762.500(6), F.A.C.

(b) All new aboveground storage tanks shall be installed in a manner consistent with the applicable requirements found in NFPA No. 30. Approval from the local fire marshal or building department may be needed before construction starts, but shall not substitute for the requirements of NFPA No. 30.

(c) All new aboveground tanks shall be supported on a well drained stable foundation which prevents movement, rolling or structurally unacceptable settling of the tank and is designed to minimize corrosion of the tank bottom.

(d) Cathodic protection for tank bottoms.

1. Bottoms of new metal tanks which rest on or in the soil contained within the secondary containment system shall be cathodically protected with sacrificial anodes or an impressed current system which is designed, constructed and installed in accordance with API RP 651 and NACE Standard Number RP-0285-85.

2. A corrosion professional shall supervise the installation of the cathodic protection system where this is necessary to assure that the system has been installed as designed.

3. Each cathodic protection system shall have a test station or a method of monitoring which enables the owner or operator to check on the adequacy of cathodic protection.

(e)1. Exterior Coatings.

2. Exterior coatings shall be designed and applied to prevent corrosion and deterioration, or for non-metallic tanks, to protect the tank from degradation by ultraviolet light. The condition of the paint or surface coating system shall be maintained to ensure continuous protection for the life of the storage tank system.

(f) Overfill Protection.

1. All owners or operators shall ensure that discharges from overfills of the storage tank system do not occur. The owner or operator shall ensure that the volume available in the tank is greater than

the volume of product to be transferred to the tank before the transfer is made and shall ensure that the transfer is monitored to prevent overfilling.

2. All tanks shall be equipped with:

a. A gauge or other measuring device which accurately shows the level of pollutant in the tank and is visible to the person who is monitoring the filling. The filling of the tank shall be monitored during filling in accordance with the provisions of API Recommended Practice 2350, if applicable; or

b. A high level warning alarm; or

c. A high level liquid pump cutoff controller or an equivalent device.

3. Manual tank gauging may be used for tanks with a capacity of 5000 gallons or less which are not loaded with high-volume pressurized nozzles. Such tanks, however, which use manual tank gauging shall not be loaded beyond 95% capacity.

4. All product loading areas where tank filling connections are made with vehicles shall be equipped with a spill containment system or other spill containment equipment of sufficient volume to prevent the discharge of the pollutant contained in the transfer hose when it is detached from the tank fill pipe.

(g) All field-erected tanks shall be inspected in accordance with API Standard 653. Any deficiency discovered during the inspection shall be repaired before the storage tank is returned to service.

(4) Piping. All integral piping, bulk product piping and hydrant piping installed after the effective date of this rule which are in contact with the soil shall be constructed with secondary containment. Integral piping containing heavy fuel oils such as American Society for Testing Materials (ASTM) grades 5 and 6 residual oils, intermediate fuel oils with a viscosity of 30 and higher, or Bunker C are exempt from this requirement. All integral piping systems which are not in contact with soil shall be constructed in accordance with accepted engineering practices and NFPA 30, Chapter 3. Integral piping in contact with the soil shall be constructed of one or more of the following materials and in accordance with the following referenced standards:

(a) Fiberglass reinforced plastic in accordance with UL 971 and UL 567;

(b) Cathodically protected coated steel in accordance with NFPA Standard 30, API RP 1615, API RP 1632, NACE RP-0169-83 and NACE RP-0285-85 or STI R892-89, provided that:

1. The piping is coated with a suitable dielectric material;

2. Any field-installed cathodic protection system is designed by a corrosion professional;

3. Any impressed current system is designed to allow for a determination of operating status; and

4. All cathodic protection systems are operated and maintained in accordance with Rule 17-762.730, F.A.C.; or

(c) Other material, design, construction or corrosion protection as determined by the Department to be sufficient to prevent the release of any stored pollutant in a manner that is no less protective of human health and the environment than the requirements of this section. Such a determination shall be made in accordance with Rule 17-762.850, F.A.C.

(5)(a) Airport and Seaport Hydrant Pits.

(b) Underground hydrant pits shall be installed with a spill catchment basin, secondary containment or other spill prevention equipment to prevent the discharge of pollutants during fueling of aircraft or vessels or at any other time the hydrant system is in use. Any such equipment shall be sealed to and around the hydrant piping with an impervious, compatible material.

[redacted]

(a) No person shall construct, use or maintain any new aboveground tank without having constructed around and under it a secondary containment system. An impervious secondary containment system shall be designed and installed to direct any release to a monitoring point or points or a treatment system if necessary. Except as provided in Chapter 17-762.500(6)(a)2., F.A.C., secondary containment shall conform to the requirements of NFPA 30, Chapter 2-2.3, regardless of whether the tank is in contact with the containment or supported above it. Storage tank systems containing heavy fuel [redacted] American Society [redacted] grades 5 and 6 [redacted] with a viscosity of 30 and higher, or Bunker C are exempt from the requirements for secondary containment and release detection. The secondary containment system, including the area under the tanks, shall:

1. Be impervious to the types of pollutants stored in the tanks;

2. Contain at least 110 percent of the volume of the tank or of the largest tank within the secondary containment unless the tank is contained in an enclosed concrete vault or is a double wall tank; and

3. If not roofed or otherwise protected from the accumulation of rainfall, be equipped with a manually controlled pump or siphon, or a gravity drain pipe which has a manually controlled valve to remove stormwater that collects within the secondary containment system. All pumps, siphons and valves must be properly maintained and kept in good condition to prevent stormwater leaking from the system. If gravity drain pipes are used, all valves shall be locked in a closed position except when the operator is in the process of draining water from the area. Gravity drain pipes shall be designed and constructed to prevent a release in the event of fire. All piping passing through secondary containment walls shall be sealed around the outside of the piping with an impervious compatible material to prevent the discharge of pollutants. Stormwater or industrial wastewater emanating from the secondary containment system and tank drawdown water shall comply with all applicable state and federal requirements before discharge. Accumulated stormwater shall be drawn off within one week of a rainfall event.

(b) Any synthetic liner used as secondary containment must be puncture resistant, have a

permeability rate to the pollutant stored of $1x10^{-7}$ cm/sec. or less, be capable of containing pollutants for at least 30 days, and be of a type approved by the Department pursuant to Rule 17-762.860, F.A.C. Criteria to be reviewed by the Department for approval of a synthetic liner shall include thickness, strength, durability, and compatibility.

(c) Any concrete liner used as secondary containment shall be designed and constructed to be product tight, and of sufficient thickness and strength to prevent a discharge during its operating life.

(d) Secondary containment shall be designed and installed to direct a discharge from the storage tank system to a monitoring point or points.

(e) Secondary containment incorporating clay-based composite products or off-site natural clays shall be approved by the Department in accordance with 17-762.850, F.A.C.

Specific Authority 376.303 FS. Law Implemented 376.303 FS. History—New 3-12-91.

17-762.510 Performance Standards for Existing Shop-Fabricated Storage Tank Systems.

(1) Vehicular Fuel Storage Systems. All shop-fabricated storage tanks with capacities greater than 550 gallons that contain vehicular fuel and that were subject to Chapter 17-61, F.A.C., shall have met the requirements of such chapter by January 1, 1990. By December 31, 1999, all vehicular fuel storage systems shall meet the requirements of Rule 17-762.500(3)(d) through (f) and (4), F.A.C., for cathodic protection, exterior coatings, overfill protection, and integral piping in contact with the soil.

(2) All shop-fabricated storage tanks that contain vehicular fuel which store or use 1,000 gallons or less per month or 10,000 gallons or less per year shall meet the requirements of Rule 17-762.500(3)(d) through (f), and (4), and (6), F.A.C., by December 31, 1999.

(3) All integral piping in contact with the soil which is installed on an existing storage tank system containing pollutants after the effective date of this rule, excluding integral piping installed during a repair, shall meet the requirements of Rule 17-762.500(4) and 17-762.600(4), F.A.C., by December 31, 1999.

(4) All marine fueling facilities, all storage tanks containing other pollutants that are not vehicular fuels, [illegible] other [illegible] chlorinated, pesticides and derivatives thereof, shall meet the requirements of Rule 17-762.500(3)(d) through (f) and [illegible], F.A.C., by December 31, 1999.

(5) In place of installing the secondary containment underneath the storage tank, the interior bottom of the storage tank and at least 18 inches up the sides may be coated with an epoxy coating or other suitable material which is impervious to the pollutant to be stored in accordance with API RP 652, by December 31, 1999. Secondary containment must nonetheless be installed around the storage tank as required by Rule 17-762.500(6), F.A.C.

(6) A closure assessment shall be performed in accordance with Section 17-762.800(2)(d), F.A.C., before the completion of the installation of secondary containment.

Specific Authority 376.303 FS. Law Implemented 376.303 FS. History—New 3-12-91.

17-762.520 Performance Standards for Existing Field-Erected Storage Tank Systems.

(1) Tanks

(a) All field-erected storage tanks that contain pollutants shall meet the requirements of Rule 17-762.500(3)(d) through (g) and (6), and perform a baseline internal inspection in accordance with API Standard 653, by December 31, 1999.

(b) When the bottom of a storage tank is replaced, secondary containment must be installed beneath the tank. In place of installing secondary containment underneath an existing storage tank, the interior bottom of the tank and at least 18 inches up the sides may be coated with an epoxy coating or other suitable material which is impervious to the pollutant to be stored in accordance with API RP 652. Secondary containment must nonetheless be installed around the storage tank as required by Rule 17-762.500(6), F.A.C., by December 31, 1999.

(2) Piping

(a) All integral piping in contact with the soil, except for hydrant piping and bulk product piping shall be upgraded with secondary containment according to the standards of Rule 17-762.500(4), F.A.C., by December 31, 1999.

(b) Instead of installing secondary containment, existing hydrant piping and bulk product piping shall:

1. Be assessed for structural integrity and tightness in accordance with API RP 1110 or an equivalent method by January 1, 1993. Chapter 17-762.700, F.A.C., procedures shall be followed if repairs are needed as a result of the assessment, and discharge response requirements of Rule 17-762.820, F.A.C., shall be followed if a release is discovered. An annual pressure test shall be performed thereafter until December 31, 1999, when facility owners and operators must comply with Chapter 17-762.600(7), F.A.C.

2. Be equipped with a cathodic protection system installed or approved by a corrosion professional in accordance with Rule 17-762.500(4)(b), F.A.C., by December 31, 1999 for piping in contact with the soil.

(3) Hydrant pits shall meet the requirements of Rule 17-762.500(5), F.A.C., by December 31, 1999.

(4) A closure assessment shall be performed in accordance with Section 17-762.800(2)(d), F.A.C., before the completion of the installation of secondary containment.

Specific Authority 376.303 FS. Law Implemented 376.303 FS. History—New 3-12-91.

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STATE OF FLORIDA
DEPARTMENT OF STATE

Division of Elections

I, GLENDA E. HOOD, Secretary of State of the State of Florida, do hereby certify that the above and foregoing is a true and correct copy of Rule 17-762.500, Florida Administrative Code, rules and regulations of the Department of Environmental Regulation, filed pursuant to Chapter 120, Florida Statutes, and was in full force and effect on March 12, 1991, as shown by the records of this office.

Given under my hand and the Great Seal of the State of Florida at Tallahassee, the Capitol, this the 2nd. day of September, A.D., 2003.

Glenda E. Hood

Secretary of State

DSDE 99 (1/03)

If photocopied or chemically altered, the word "VOID" will appear.

"State of Florida" appears in small letters across the face of this 8 1/2 X 11" document.

The original document has a reflective line mark in paper. Hold at an angle to view when checking.

permeability rate to the pollutant stored of 1x10-7 cm/sec. or less, be capable of containing pollutants for at least 30 days, and be of a type approved by the Department pursuant to Rule 17-762.860, F.A.C. Criteria to be reviewed by the Department for approval of a synthetic liner shall include thickness, strength, durability, and compatibility.

(c) Any concrete liner used as secondary containment shall be designed and constructed to be product tight, and of sufficient thickness and strength to prevent a discharge during its operating life.

(d) Secondary containment shall be designed and installed to direct a discharge from the storage tank system to a monitoring point or points.

(e) Secondary containment incorporating clay-based composite products or off-site natural clays shall be approved by the Department in accordance with 17-762.850, F.A.C.

Specific Authority 376.303 FS. Law Implemented 376.303 FS. History—New 3-12-91.

17-762.510 Performance Standards for Existing Shop-Fabricated Storage Tank Systems.

(1) Vehicular Fuel Storage Systems. All shop-fabricated storage tanks with capacities greater than 550 gallons that contain vehicular fuel and that were subject to Chapter 17-61, F.A.C., shall have met the requirements of such chapter by January 1, 1990. By December 31, 1999, all vehicular fuel storage systems shall meet the requirements of Rule 17-762.500(3)(d) through (f) and (4), F.A.C., for cathodic protection, exterior coatings, overfill protection, and integral piping in contact with the soil.

(2) All shop-fabricated storage tanks that contain vehicular fuel which store or use 1,000 gallons or less per month or 10,000 gallons or less per year shall meet the requirements of Rule 17-762.500(3)(d) through (f), and (4), and (6), F.A.C., by December 31, 1999.

(3) All integral piping in contact with the soil which is installed on an existing storage tank system containing pollutants after the effective date of this rule, excluding integral piping installed during a repair, shall meet the requirements of Rule 17-762.500(4) and 17-762.600(4), F.A.C., by December 31, 1999.

(4) [redacted] all storage tanks [redacted] vehicular fuels and [redacted] systems other than those containing [redacted] gasoline, pesticides [redacted] shall meet the requirements of Rule 17-762.500(3)(d) through (f) [redacted] 1999.

(5) In place of installing the secondary containment underneath the storage tank, the interior bottom of the storage tank and at least 18 inches up the sides may be coated with an epoxy coating or other suitable material which is impervious to the pollutant to be stored in accordance with API RP 652, by December 31, 1999. Secondary containment must nonetheless be installed around the storage tank as required by Rule [redacted] F.A.C.

(6) A closure assessment shall be performed in accordance with Section 17-762.800(2)(d), F.A.C., before the completion of the installation of secondary containment.

Specific Authority 376.303 FS. Law Implemented 376.303 FS. History—New 3-12-91.

17-762.520 Performance Standards for Existing Field-Erected Storage Tank Systems.

(1) Tanks

(a) All field-erected storage tanks that contain pollutants shall meet the requirements of Rule 17-762.500(3)(d) through (g) and (6), and perform a baseline internal inspection in accordance with API Standard 653 [redacted]

(b) When the bottom of a storage tank is replaced, secondary containment must be installed beneath the tank. In place of installing secondary containment underneath an existing storage tank, the interior bottom of the tank and at least 18 inches up the sides may be coated with an epoxy coating or other suitable material which is impervious to the pollutant to be stored in accordance with API RP 652. Secondary containment must nonetheless be installed around the storage tank as required by Rule 17-762.500(6), F.A.C., [redacted] December 31, 1999.

(2) Piping

(a) All integral piping in contact with the soil, except for hydrant piping and bulk product piping shall be upgraded with secondary containment according to the standards of Rule 17-762.500(4), F.A.C., [redacted] 1999.

(b) Instead of installing secondary containment, existing hydrant piping and bulk product piping shall:

1. Be assessed for structural integrity and tightness in accordance with API RP 1110 or an equivalent method by January 1, 1993. Chapter 17-762.700, F.A.C., procedures shall be followed if repairs are needed as a result of the assessment, and discharge response requirements of Rule 17-762.820, F.A.C., shall be followed if a release is discovered. An annual pressure test shall be performed thereafter until December 31, 1999, when facility owners and operators must comply with Chapter 17-762.600(7), F.A.C.

2. Be equipped with a cathodic protection system installed or approved by a corrosion professional in accordance with Rule 17-762.500(4)(b), F.A.C., by December 31, 1999 for piping in contact with the soil.

(3) Hydrant pits shall meet the requirements of Rule 17-762.500(5), F.A.C., by December 31, 1999.

(4) A closure assessment shall be performed in accordance with Section 17-762.800(2)(d), F.A.C., before the completion of the installation of secondary containment.

Specific Authority 376.303 FS. Law Implemented 376.303 FS. History—New 3-12-91.

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STATE OF FLORIDA
DEPARTMENT OF STATE

Division of Elections

I, GLENDA E. HOOD, Secretary of State of the State of Florida, do hereby certify that the above and foregoing is a true and correct copy of Rule 17-762.510, Florida Administrative Code, rules and regulations of the Department of Environmental Regulation, filed pursuant to Chapter 120, Florida Statutes, and was in full force and effect on March 12, 1991, as shown by the records of this office.

Given under my hand and the Great Seal of the State of Florida at Tallahassee, the Capitol, this the 2nd. day of September, A.D., 2003.

Glenda E. Hood

Secretary of State

DSDE 99 (1/03)

The original document has a reflective line mark in paper. Hold at an angle to view when checking.

permeability rate to the pollutant stored of 1×10^{-7} cm/sec. or less, be capable of containing pollutants for at least 30 days, and be of a type approved by the Department pursuant to Rule 17-762.860, F.A.C. Criteria to be reviewed by the Department for approval of a synthetic liner shall include thickness, strength, durability, and compatibility.

(c) Any concrete liner used as secondary containment shall be designed and constructed to be product tight, and of sufficient thickness and strength to prevent a discharge during its operating life.

(d) Secondary containment shall be designed and installed to direct a discharge from the storage tank system to a monitoring point or points.

(e) Secondary containment incorporating clay-based composite products or off-site natural clays shall be approved by the Department in accordance with 17-762.850, F.A.C.

Specific Authority 376.303 FS. Law Implemented 376.303 FS. History—New 3-12-91.

17-762.510 Performance Standards for Existing Shop-Fabricated Storage Tank Systems.

(1) Vehicular Fuel Storage Systems. All shop-fabricated storage tanks with capacities greater than 550 gallons that contain vehicular fuel and that were subject to Chapter 17-61, F.A.C., shall have met the requirements of such chapter by January 1, 1990. By December 31, 1999, all vehicular fuel storage systems shall meet the requirements of Rule 17-762.500(3)(d) through (f) and (4), F.A.C., for cathodic protection, exterior coatings, overfill protection, and integral piping in contact with the soil.

(2) All shop-fabricated storage tanks that contain vehicular fuel which store or use 1,000 gallons or less per month or 10,000 gallons or less per year shall meet the requirements of Rule 17-762.500(3)(d) through (f), and (4), and (6), F.A.C., by December 31, 1999.

(3) All integral piping in contact with the soil which is installed on an existing storage tank system containing pollutants after the effective date of this rule, excluding integral piping installed during a repair, shall meet the requirements of Rule 17-762.500(4) and 17-762.600(4), F.A.C., by December 31, 1999.

(4) All marine fueling facilities, all storage tanks containing other pollutants that are not vehicular fuels, and petroleum storage tank systems, other than those containing ammonia, chlorine, pesticides and derivatives thereof, shall meet the requirements of Rule 17-762.500(3)(d) through (f) and (4), and (6), F.A.C., by December 31, 1999.

(5) In place of installing the secondary containment underneath the storage tank, the interior bottom of the storage tank and at least 18 inches up the sides may be coated with an epoxy coating or other suitable material which is impervious to the pollutant to be stored in accordance with API RP 652, by December 31, 1999. Secondary containment must nonetheless be installed around the storage tank as required by Rule 17-762.500(6), F.A.C.

(6) A closure assessment shall be performed in accordance with Section 17-762.800(2)(d), F.A.C., before the completion of the installation of secondary containment.

Specific Authority 376.303 FS. Law Implemented 376.303 FS. History—New 3-12-91.

17-762.520 Performance Standards for Existing Field-Erected Storage Tank Systems.

(1) Tanks

(a) All field-erected storage tanks that contain pollutants shall meet the requirements of Rule 17-762.500(3)(d) through (g) and (6), and perform a baseline internal inspection in accordance with API Standard 653, by December 31, 1999.

(b) When the bottom of a storage tank is replaced, secondary containment must be installed beneath the tank. In place of installing secondary containment underneath an existing storage tank, the interior bottom of the tank and at least 18 inches up the sides may be coated with an epoxy coating or other suitable material which is impervious to the pollutant to be stored in accordance with API RP 652. Secondary containment must nonetheless be installed around the storage tank as required by Rule 17-762.500(6), F.A.C., by December 31, 1999.

(2) Piping

(a) All integral piping in contact with the soil, except for hydrant piping and bulk product piping shall be upgraded with secondary containment according to the standards of Rule 17-762.500(4), F.A.C., by December 31, 1999.

(b) Instead of installing secondary containment, existing hydrant piping and bulk product piping shall:

1. Be assessed for structural integrity and tightness in accordance with API RP 1110 or an equivalent method by January 1, 1993. Chapter 17-762.700, F.A.C., procedures shall be followed if repairs are needed as a result of the assessment, and discharge response requirements of Rule 17-762.820, F.A.C., shall be followed if a release is discovered. An annual pressure test shall be performed thereafter until December 31, 1999, when facility owners and operators must comply with Chapter 17-762.600(7), F.A.C.

2. Be equipped with a cathodic protection system installed or approved by a corrosion professional in accordance with Rule 17-762.500(4)(b), F.A.C., by December 31, 1999 for piping in contact with the soil.

(3) Hydrant pits shall meet the requirements of Rule 17-762.500(5), F.A.C., by December 31, 1999.

(4) A closure assessment shall be performed in accordance with Section 17-762.800(2)(d), F.A.C., before the completion of the installation of secondary containment.

Specific Authority 376.303 FS. Law Implemented 376.303 FS. History—New 3-12-91.

A black and white copy of this document is not official

STATE OF FLORIDA
DEPARTMENT OF STATE

Division of Elections

I, GLENDA E. HOOD, Secretary of State of the State of Florida, do hereby certify that the above and foregoing is a true and correct copy of Rule 17-762.520, Florida Administrative Code, rules and regulations of the Department of Environmental Regulation, filed pursuant to Chapter 120, Florida Statutes, and was in full force and effect on March 12, 1991, as shown by the records of this office.

Given under my hand and the Great Seal of the State of Florida at Tallahassee, the Capitol, this the 2nd. day of September, A.D., 2003.

Glenda E. Hood

Secretary of State

DSDE 99 (1/03)

If photocopied or chemically altered, the word "VOID" will appear.

"State of Florida" appears in small letters across the face of this 8½ X 11" document.

The original document has a reflective line mark in paper. Hold at an angle to view when checking.

PROGRESS ENERGY FLORIDA
Docket 030711-EI
Staff's First Set of Interrogatories
Attachment to Question #2

CATEGORY

Asset Description		In-Service Date	Location	Initial Amount	Account Number and Name	Estimated Current Accumulated Depreciation	Accumulated Depreciation Acct Number & Name	Current Net Plant Balance	Substance Stored
Light Oil Storage Tank	A	Oct-74	Anclote Steam	$ 46,830	312 - Boiler Plant Equipment	$ 46,830	10811F - A/D - Steam	$ -	#2 Light Oil
Light Oil Storage Tank	A	Oct-74	Anclote Steam	46,830	312 - Boiler Plant Equipment	46,830	10811F - A/D - Steam	0	#2 Light Oil
Jet Fuel Storage Tank	A	Feb-68	Avon Park Peaking	29,672	342 - Fuel Holders, Producers, Accessories	29,672	10815F - A/D - Other	0	#2 Light Oil
Oil Storage Tank #6	A	Jun-72	Bartow Peaking	308,462	342 - Fuel Holders, Producers, Accessories	308,462	10815F - A/D - Other	0	#2 Light Oil
Oil Storage Tank #6 Addtn	B	Aug-94	Bartow Peaking	225,690	342 - Fuel Holders, Producers, Accessories	115,779	10815F - A/D - Other	109,911	#2 Light Oil
Fuel Oil Tank #1	A	Apr-73	Bayboro Peaking	125,262	342 - Fuel Holders, Producers, Accessories	112,736	10815F - A/D - Other	12,526	#2 Light Oil
Fuel Oil Tank #2	A	Apr-73	Bayboro Peaking	117,843	342 - Fuel Holders, Producers, Accessories	106,059	10815F - A/D - Other	11,784	#2 Light Oil
Light Oil Tank	A	Jun-79	Crystal River 1 & 2	94,172	312 - Boiler Plant Equipment	94,172	10811F - A/D - Steam	0	#2 Light Oil
Fuel Oil Tank #2	A	Jun-75	Debary Peaking Common	702,087	342 - Fuel Holders, Producers, Accessories	702,087	10815F - A/D - Other	0	#2 Light Oil
Fuel Oil Tank #1	A	May-74	Intercession City Peaking	338,474	342 - Fuel Holders, Producers, Accessories	338,474	10815F - A/D - Other	0	#2 Light Oil
Fuel Oil Tank #2	A	May-74	Intercession City Peaking	338,474	342 - Fuel Holders, Producers, Accessories	338,474	10815F - A/D - Other	0	#2 Light Oil
Oil Storage Tank #1 Addtn	B	Oct-93	Intercession City Peaking 7-10	364,428	342 - Fuel Holders, Producers, Accessories	127,550	10815F - A/D - Other	236,878	#2 Light Oil
Oil Storage Tank #2 Addtn	B	Oct-93	Intercession City Peaking 7-10	364,428	342 - Fuel Holders, Producers, Accessories	127,550	10815F - A/D - Other	236,878	#2 Light Oil
Fuel Oil Tank	B	Dec-92	Rio Pinar Peaker	126,866	342 - Fuel Holders, Producers, Accessories	87,918	10815F - A/D - Other	38,948	#2 Light Oil
Fuel Oil Tank #3	A	Oct-80	Suwannee River Peaking	588,772	342 - Fuel Holders, Producers, Accessories	588,772	10815F - A/D - Other	0	#2 Light Oil
Storage Tank #7	A	Aug-74	Turner Peaking	323,952	342 - Fuel Holders, Producers, Accessories	323,952	10815F - A/D - Other	0	#2 Light Oil
Storage Tank # 7 Addtn	B	Dec-97	Turner Peaking	216,561	342 - Fuel Holders, Producers, Accessories	62,370	10815F - A/D - Other	154,191	#2 Light Oil
Fuel Oil Tank	B	Jan-94	University of Florida Co-Gen	117,902	342 - Fuel Holders, Producers, Accessories	61,545	10815F - A/D - Other	56,357	#2 Light Oil
				$ 4,476,705		$ 3,619,232		$ 857,473	

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Progress Energy Florida
Docket No. 030711
Answers to Staff's 1st Ints.
Attachment 2-1

Progress Energy

Tank Maintenance - #2 Fuel Oil
Florida Plants
Docket #030711-EI
Staff's 1st Set of Interrogatories
Attachment to Question #3

Item No.	Description	Location	Tank #	Major Upgrade Date	W.O. #	Cost O&M	Cost Capital	Environmental Regulation	Compliance Deadline	Capital FERC Account	O&M FERC Account
1	Tank Upgrade - including cleaning, baseline inspection, necessary repairs, cathodic protection installation, & internal lining.	**Anclote**	1	October-97	WF2254	8,150	495,000	FDEP - Chapter 62-761	July-98	107000	514000
2	"		2	October-96	WF2254	8,150	495,000	"	July-98	107000	514000
3	Routine O&M**			Since '92	N/A	50,000	N/A	N/A	N/A		514000
4	"	**Avon Park**	5	August-97	WG0406	16,800	189,504	"	July-98	107000	554000
5	"	**Bartow**	6	March-94	WG0253	23,900	257,021	"	July-98	107000	514000
6	Routine O&M**			Since '99	N/A	6,500	N/A	N/A	N/A		514000
7	"	**Bayboro**	1	September-96	WG0436	33,500	93,022	"	July-98	107000	554000
8	"		2	July-92	WG0184	33,000	93,522	"	July-98	107000	554000
9	"	**C.R.South**	1	April-98	WF 2276	38,500	64,000	"	July-98	107000	514000
10	Routine O&M**			Since '92	N/A	17,000	N/A	N/A	N/A		514000
11	"	**Debary**	2	October-97	WG0437	49,900	216,937	"	July-98	107000	554000
12	"	**Int. City***	1	December-92	RIC901	25,600	23,395	"	July-98	107000	554000
13	"		2	March-93	RIC901	21,100	23,395	"	July-98	107000	554000
14	"	**Rio Pinar**	1		WG0059	6,000	-	"	July-98	107000	554000
15	"	**Suwannee**	10	April-99	WG0424	202,100	272,000	"	December-00	107000	554000
16	"	**Turner**	7	February-97	WG0404	26,000	276,119	"	July-98	107100	554000
17	"	**U. of F.**	1	January-98	RUF901	29,500	27,454	"	July-98	1071000	554000
18	Grand Total					$ 595,700	$ 2,526,367				

* Intercession city tank upgrades charged in unit 7-10 construction work order.

**Represents routine O&M tank work such as value inspections, fire protection upkeep, ground maintenance, monthly strappings readings, leak detection, heating coil repair and roof repair.

↑ ? SECONDARY CONTAINMENT.

Progress Energy Florida
Docket No. 030711
Answers to Staff's 1st Ints.
Attachment 3-1

Progress Energy
Aboveground Storage Tank Compliance Upgrades
Included in ECRC Petition

Site	No. of Regulated Tanks on Site	FDEP ID of AST Systems	Scope of Work / Regulatory Citation	Start / Completion Dates
Anclote	*2*	*#1, #2*	Anclote tanks #1 & 2 contain No. 2 oil (diesel fuel), and are subject to 62-761.510 (3)(d) Table AST U (1) to install secondary containment. 62-761.510 (3)(d) Table AST U (2) does not apply because none of the pipe is in contact with the soil.	No specific scheduled currently established: 2008 or 2009.
Avon Park	*1*	*#5*	Avon Park tank #5 is a No. 2 oil (diesel fuel) tank that is subject to 62-761.510 (3)(d) Table AST U (1) to install secondary containment. No piping is in contact with the soil; therefore no piping work is proposed.	This work is scheduled begin and be completed during the first quarter of 2008.
Bartow	*1*	*#11*	Bartow tank #11 contains No. 2 oil (diesel fuel),and is subject to 62-761.510 (3)(d) Table AST U (1) requiring the installation of secondary containment; and, to 62-761.510 (3)(d) Table AST U (2)(a) which requires the double–walling of pipe in contact with the soil.	Piping work is to be started in September 2003 and completed in December 2003; secondary containment is scheduled to begin and be completed in early 2009.
Bayboro	*2*	*#12, #13*	Bayboro tanks #12 and #13 are No. 2 oil (diesel fuel) tanks that are subject 62-761.510 (3)(d) Table AST U (1) to install secondary containment. The underground barge offloading line (that transports fuel to the ASTs) is subject to 62-761.510 (3)(d) Table AST U (2)(a) to double wall pipe in contact with the soil.	The current project schedule is to start and complete secondary containment on both tanks between the 4th quarter of 2006 and the first quarter of 2007. All piping changes are expected to be started and completed within the second quarter of 2007.

Progress Energy Florida
Docket No. 030711
Answers to Staff's 1st Ints
Attachment 5-1

Progress Energy
Aboveground Storage Tank Compliance Upgrades
Included in ECRC Petition

Site	*No. of Regulated Tanks on Site*	*FDEP ID of AST Systems*	*Scope of Work / Regulatory Citation*	*Start / Completion Dates*
Crystal River	*3*	*#2*	Crystal River South has one No. 2 oil (diesel fuel) tank that is within a concrete secondary containment. This tank must be upgraded per 62-761.510 (3)(d) Table AST W (1) to install secondary containment. There is no pipe in contact with the soil.	Scheduled start date is September 2003; scheduled completion is December 2003.
DeBary	*1*	*#23*	DeBary tank #23 is a No. 2 oil (diesel fuel) tank that is subject to 62-761.510 (3)(d) Table AST U (1) to install secondary containment and to 62-761.510 (3)(d) Table AST U (2)(a)to double wall pipe in contact with soil.	Work is scheduled to be started and completed during the second quarter of 2005.
Intercession City	*2*	*#17, #18*	Intercession City tanks #17 and #18 are No. 2 oil tanks that are subject to 62-761.510 (3)(d) Table AST U (1) to install secondary containment and to 62-761.510 (3)(d) Table AST U (2)(a) to double wall pipe in contact with the soil.	Double-bottoming work will be initiated and completed for tank #18 during the first quarter of 2005. Tank #17 will be upgraded during the second quarter of 2006. All piping work will be performed during the second quarter of 2006.
Rio Pinar	*1*	*#2*	Rio Pinar tank #2 is a No. 2 oil tank that is within a concrete secondary containment and is subject to the upgrade required by 62-761.510 (3)(d) Table AST W (1) to install secondary containment. There is no pipe in contact with the soil.	The schedule for this work is flexible, but will be completed by the established deadline.
Suwannee	*1*	*#24*	Suwannee tank #24 contains No. 2 oil (diesel fuel), and	All work is scheduled to

Progress Energy Aboveground Storage Tank Compliance Upgrades Included in ECRC Petition				
Site	**No. of Regulated Tanks on Site**	**FDEP ID of AST Systems**	**Scope of Work / Regulatory Citation**	**Start / Completion Dates**
			is subject to 62-761.510 (3)(d) Table AST U (1) to install secondary containment; and, to 62-761.510 (3)(d) Table AST U (2)(a) to double wall pipe in contact with the soil.	begin and be completed during the fourth quarter of 2005.
Turner	*1*	*#2*	Turner tank #2 is a No. 2 oil (diesel fuel) tank subject to 62-761.510 (3)(d) Table AST U (1) to install secondary containment. No piping will be in contact with the soil; therefore, 62-761.510 (3)(d) Table AST U (2) does not apply.	Preparation work began at this site in July 2003, and will be completed by the end of 2003.
University of Florida	*1*	*#3*	University of Florida tank #3 is a No. 2 oil (diesel fuel) tank that is subject to 62-761.510 (3)(d) Table AST U (1) to install secondary containment. There is no pipe in contact with the soil.	This work is scheduled to be started and completed during the third quarter of 2006.

Progress Energy
Aboveground Storage Tank Compliance Upgrades
Not Included in ECRC Petition

Site	*No. of Regulated Tanks on Site*	*FDEP ID of AST Systems*	*Scope of Work / Regulatory Citation*	*Start / Completion Dates*
Crystal River	*3*	*#3, #13*	Crystal River North has two No. 2 oil (fuel oil) tanks that are subject to 62-761.510 (3)(d) Table AST U (1) to install secondary containment.	The required upgrades to these tanks were started in July 2003 and is approximately 50% complete. Completion is expected in December 2003.
Higgins	*1*	*#1*	Higgins tank # 1 is a No. 2 oil tank that is subject to 62-761.510 (b)(3) Table AST U (1) to install secondary containment.	The required upgrades were completed in March and May 2003.
Jamestown Operations Center	*2*	*#1R1, #5*	These are small tanks that were previously upgraded in accordance with 62-761.510 (3)(d) Table AST V (4) to seal secondary containment.	The deadline for completion was January 1, 2000, and the project was completed on time.
Monticello Garage	*1*	*#5*	This was a small tank that was previously upgraded in accordance with 62-761.510 (3)(d) Table AST V (4) to seal secondary containment. The tank has since been removed from the site and there are no regulated ASTs remaining on site at this time.	The deadline for completion was January 1, 2000, and the project was completed on time.

Progress Energy Florida
Docket No. 030711
Answers to Staff's 1st Ints.
Attachment 5-2

Progress Energy Florida (PEF) *Aboveground Storage Tanks – Identification Numbers* *ECRC Petition* *October 14, 2003*		
Facility Name	**FDEP Tank ID**	**PEF Tank ID**
Anclote	#1, #2	#1, #2
Avon Park	#5	#5
Bartow	#11	#6
Bayboro	#12, #13	#1, #2
Crystal River South	#2	#10
DeBary	#23	#2
Intercession City	#17, #18	#2, #1
Rio Pinar	#2	#3
Suwannee	#24	#10
Turner	#2	#7
University of Florida	#3	#1 (only No. 2 Fuel oil tank on site)

Progress Energy Florida (PEF) *Aboveground Storage Tanks – Identification Numbers* *ECRC Petition* *October 14, 2003*		
Facility Name	**FDEP Tank ID**	**PEF Tank ID**
Anclote	#1, #2	#1, #2
Avon Park	#5	#5
Bartow	#11	#6
Bayboro	#12, #13	#1, #2
Crystal River South	#2	#10
DeBary	#23	#2
Intercession City	#17, #18	#2, #1
Rio Pinar	#2	#3
Suwannee	#24	#10
Turner	#2	#7
University of Florida	#3	#1 (only No. 2 Fuel oil tank on site)

Part of Comp. Exh. 8 ~~Part 2 Enforcement~~ PIM & ASTSC rec filed on 10/22/03

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: OCTOBER 22, 2003

TO: DIRECTOR, DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE SERVICES (BAYÓ)

FROM: DIVISION OF ECONOMIC REGULATION (BREMAN)
OFFICE OF THE GENERAL COUNSEL (STERN, VINING)

RE: DOCKET NO. 030711-EI - PETITION OF PROGRESS ENERGY FLORIDA, INC. FOR APPROVAL OF NEW ENVIRONMENTAL PROGRAMS FOR COST RECOVERY THROUGH ENVIRONMENTAL COST RECOVERY CLAUSE.

AGENDA: 11/3/2003 - REGULAR AGENDA - PROPOSED AGENCY ACTION - INTERESTED PERSONS MAY PARTICIPATE

CRITICAL DATES: NONE

SPECIAL INSTRUCTIONS: NONE

FILE NAME AND LOCATION: S:\PSC\ECR\WP\030711.RCM

CASE BACKGROUND

On July 28, 2003, Progress Energy Florida, Inc. ("PEF") filed a Petition for approval of the Pipeline Integrity Management Program ("PIM") and the Aboveground Storage Tank Secondary Containment Project ("ASTSC") as two new activities for cost recovery through the Environmental Cost Recovery Clause ("ECRC").

The PIM program consists primarily of upgrades and continual integrity testing of a 14-inch fuel oil pipeline which extends 33 miles from PEF's Bartow Power Plant to its Anclote Power Plant. PEF's petition states that the PIM program is required to comply with the U.S. Department of Transportation Regulation 49 CFR Part 195, as amended on February 15, 2002.

The ASTSC project consists primarily of installing secondary containment for 12 tanks and upgrades to two dike fields. PEF's

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030007-EI EXHIBIT NO. Comp. Ex. 8
COMPANY/ Progress Energy Staff
WITNESS: Rec. in DF# 030711-EI
DATE: 11-12-03

petition states that the ASTSC project is required to comply with the provisions of Florida Department of Environmental Protection Rule 62-761.510, Florida Administrative Code.

Section 366.8255, Florida Statutes, the ECRC, gives the Commission the authority to review and decide whether a utility's environmental compliance costs are recoverable through a cost recovery factor. Electric utilities may petition the Commission to recover projected environmental compliance costs required by environmental laws or regulations. See Section 366.8255(2), Florida Statutes. Environmental laws or regulations include "all federal, state or local statutes, administrative regulations, orders, ordinances, resolutions, or other requirements that apply to electric utilities and are designed to protect the environment." Section 366.8255(1)(c). If the Commission approves the utility's petition for cost recovery through this clause, only prudently incurred costs shall be recovered. See Section 366.8255(2), Florida Statutes.

DISCUSSION OF ISSUES

ISSUE 1: Should the Commission approve Progress Energy Florida, Inc.'s petition for the Pipeline Integrity Management ("PIM") project as a new activity for cost recovery through the ECRC?

RECOMMENDATION: Yes. The PIM program is required to comply with Regulation 49 CFR Part 195, as amended on February 15, 2002. The resultant environmental compliance costs are incremental to PEF's base rates because the requirements of 49 CFR Part 195 did not affect PEF prior to the company's 2002 rate case (Docket No. 000824-EI). (Breman, Stern)

STAFF ANALYSIS: PEF is implementing the PIM program to comply with the U.S. Department of Transportation's regulations in 49 CFR Part 195. The regulation applies to pipelines with 500 or fewer miles that transport hazardous substances across or near population centers, environmentally sensitive areas and commercially navigable waters. The operators of such pipelines must manage pipeline integrity to ensure that leaks do not occur.

The PIM program addresses initial inspecting and testing, upgrades, and continual integrity assessment of a 14-inch fuel oil

pipeline which extends 33 miles from PEF's Bartow Power Plant to its Anclote Power Plant. PEF states that it does not seek recovery of the costs incurred prior to filing this petition. The petition costs to be excluded from the ECRC are for initial pipeline identification, development of the integrity management program, and a leak detection study. Staff notes that excluding costs that have already been incurred is consistent with Section 366.8255(2), Florida Statutes, and Order No. PSC-94-1207-FOF-EI, issued October 3, 1994, Docket No. 940042, In Re: Environmental Cost Recovery Clause, p.5, which provide that cost recovery is allowed for prospective costs only.

PEF seeks to recover costs incurred after July 28, 2003, the date of this petition. The projected 2003 costs are $990,000 in capital investments for an upgraded leak detection system and $10,000 in related operating and maintenance ("O&M") expenses. PEF projects it will incur an additional $245,000 in O&M expense in 2004. Competitive bidding will be used to select the lowest cost supplier of the necessary services wherever possible. Approximately every five-years PEF will have to retest and assess each pipeline segment at a cost between $150,000 and $200,000 not including upgrades that may also be required.

Staff believes that costs incurred to comply with 49 CFR Part 195 are incremental to PEF's current base rates because the requirements of 49 CFR Part 195 did not exist prior to the 2002 rate case. PEF completed its Minimum Filing Requirements budget for 2002 in July 2001 and began filing its Minimum Filing Requirements and rate case testimony on September 14, 2001. PEF became aware of the proposed changes to 49 CFR Part 195 on January 16, 2002. The environmental requirement did not become effective until February 15, 2002 which was after the intervenors and staff began filing testimony in Docket No. 000824-EI. Rate case discovery ended on March 13, 2002. Consequently, no witness could have reasonably addressed environmental compliance costs associated with 49 CFR Part 195, as amended on February 15, 2002. Based on this information staff concludes that PEF's current base rates do not provide recovery of the ongoing costs for the PIM program.

Based on the foregoing, staff believes that the PIM program satisfies the requirements of Section 366.8255, Florida Statutes, and qualifies for recovery through the ECRC. The actual expenditures will be addressed in the ECRC true-up cycle and be subject to audit. Issues that will determine the specific amount

recoverable through the ECRC, such as whether specific costs were prudently incurred and the appropriate return on investment, will be further examined and resolved in Docket No. 030007-EI. PEF is not requesting a change in the ECRC factors that have been approved for 2003. Instead, PEF included the estimated 2003 expenses for the PIM activity in its true-up calculations filed in Docket 030007-EI. Staff agrees that the PIM activity expenses do not require a mid-course correction because only 0.2 percent of PEF's estimated under-recovery for 2003 is due to the PIM activity. Therefore, the review of PEF's ECRC expenses, including the PIM program expenses, should be addressed at the November 2003 ECRC hearing.

ISSUE 2: Should the Commission approve Progress Energy Florida, Inc.'s petition for the Aboveground Storage Tank Secondary Containment ("ASTSC") project as a new activity for cost recovery through the ECRC?

RECOMMENDATION: Yes. PEF should be allowed to recover the costs incurred for the installation of or upgrades to secondary containment for field-erected above ground storage tank systems as required by the 1998 amendments incorporated into Rule 62-761.510 (Table AST, Keynotes W and U), Florida Administrative Code. (Breman, Stern)

STAFF ANALYSIS: The substantive rules on secondary containment for above ground storage tanks ("ASTs") that existed in 1991, (Rules 17-762.500 through 17-762.520, Florida Administrative Code), were revised on July 13, 1998 (Rule 62-761.510, Florida Administrative Code). PEF asserts that the 1998 amendments to the rules require certain dike fields and internally-lined single bottom ASTs and associated piping in contact with the soil, to be upgraded with secondary containment.

PEF's Petition identifies 12 ASTs and two dike fields as requiring installation of or upgrades to secondary containment in order to satisfy the 1998 amendments to Rule 62-761.510, Florida Administrative Code. The tanks are listed below.

Table 1

Power Plant Site	AST Number	Start/Completion
Anclote	#1, #2	2008/2009
Avon Park	#5	2008/2008
Bartow	#11	phased 2003-2009
Bayboro	#12, #13	2006/2007
Crystal River	#2	2003/2003
DeBary	#23	2005/2005
Intercession City	#17, #18	2005/2006
Rio Pinar	#2	not scheduled
Suwannee	#24	2005/2005
Turner	#2	2003/2003
University of Fl.	#3	2006/2006

PEF must upgrade dike fields at its Crystal River and Rio Pinar power plant sites. Upgrades to the secondary containment of the tanks must be completed by 2010, and upgrades to the secondary containment of the dike fields must be completed by 2005. The specific work required at each site and the part of the rule requiring the work is shown in Attachment 1.

Because the rule incorporates requirements that existed in 1991 plus new requirements added in 1998, it was important to determine that PEF's activities were required by the new requirements added in 1998. PEF's compliance costs for activities required by the 1991 version of the rule are assumed to be recovered through base rates. Such costs would have to be excluded from the ECRC to avoid double recovery concerns. Based on extensive discussions with PEF and the Florida Department of Environmental Protection, staff believes that the activities identified in Attachment 1 are required by additions to the rule made in 1998 and cost recovery through the ECRC is appropriate because the costs are not being recovered through base rates.

As work on this docket progressed, PEF expressed a concern that the list of covered facilities in the petition may not be complete and that it would like the approval for this project to include additional, but as yet unknown, facilities requiring secondary containment. To accommodate PEF's concerns, staff recommends broadening the scope of approval to include the specifically identified facilities plus installation of or upgrades to secondary containment for field-erected above ground storage tank systems as required by the 1998 amendments to Rule 62-761.510 (Table AST, Keynotes W and U).

Before filing its Petition, PEF had begun secondary containment work at several facilities not listed above. PEF completed secondary containment upgrades on the Higgins Power Plant AST Tank No. 1 in May 2003. Upgrades to Crystal River AST Tanks Nos. 3 and 13 began in July 2003 and are expected to be completed by December 2003. PEF states that it does not seek recovery of the costs incurred prior to July 28, 2003, the date it filed its petition. Staff notes that PEF's petition is consistent with Section 366.8255(2), Florida Statutes, and Order No. PSC-94-1207-FOF-EI, p.5, which provide that cost recovery is allowed for prospective costs only.

The projected ASTSC expenditures through 2009 are $4.6 million in capital investments. Approximately $694,000 in capital investments are projected for the last quarter of 2003. PEF is using a consultant to evaluate the tanks and associated piping and to develop a comprehensive compliance plan. However, actual remediation of the facilities will be addressed on a site-by-site basis. The site specific engineering portions of the work may be completed by internal personnel or outsourced while the actual construction will be outsourced.

Based on the foregoing, staff believes that PEF's ASTSC project shown in Table 1 and including the dike field upgrades at Crystal River and Rio Pinar satisfies the requirements of Section 366.8255, Florida Statutes. PEF is not requesting a change in the ECRC factors that have been approved for 2003. Instead, PEF included the estimated 2003 expenses for the ASTSC project in its true-up calculations filed in Docket No. 030007-EI. Staff agrees that the ASTSC project expenses do not require a mid-course correction because only 0.1 percent of PEF's estimated under-recovery for 2003 is due to the ASTSC project. Therefore, the

review of PEF's ECRC expenses, including the ASTSC project expenses, should be addressed at the November 2003 ECRC hearing.

ISSUE 3: Should this docket be closed?

RECOMMENDATION: Yes, this docket should be closed upon issuance of a Consummating Order unless a person whose substantial interests are affected by the Commission's decision files a protest within 21 days of the issuance of the proposed agency action. (STERN)

STAFF ANALYSIS: If no timely protest to the proposed agency action is filed within 21 days, this docket should be closed upon the issuance of the Consummating Order.

Progress Energy Aboveground Storage Tank Compliance Upgrades Included in ECRC Petition				
Site	**No. of Regulated Tanks on Site**	**FDEP ID of AST Systems**	**Scope of Work/Regulatory Citation**	**Start/Completion Dates**
Anclote	2	#1, #2	Anclote tanks #1 & 2 contain No. 2 oil (diesel fuel), and are subject to 62-761.510 (3)(d) Table AST U (1) to install secondary containment. 62-761.510(3)(d) Table AST U (2) does not apply because none of the pipe is in contact with the soil.	No specific scheduled currently established: 2008 or 2009
Avon Park	1	#5	Avon Park tank #5 is a No. 2 oil (diesel fuel) tank that is subject to 62-761.510 (3)(d) Table AST U(1) to install secondary containment. No piping is in contact with the soil; therefore no piping work is proposed.	This work is scheduled begin and be completed during the first quarter of 2008.
Bartow	1	#11	Bartow tank #11 contains No. 2 oil (diesel fuel), and is subject to 62-761.510 (3)(d) Table AST U (1) requiring the installation of secondary containment; and, to 62-761.510(3)(d) Table AST U(2)(a) which requires the double-walling of pipe in contact with the soil.	Piping work is to be started in September 2003 and completed in December 2003; secondary containment is scheduled to begin and be completed in early 2009.
Bayboro	2	#12, #13	Bayboro tanks #12 and #13 are No. 2 oil (diesel fuel) tanks that are subject 62-761.510(3)(d) Table AST U (1) to install secondary containment. The underground barge offloading line (that transports fuel to the ASTs) is subject to 62-761.510(3)(d) Table AST U (2)(a) to double wall pipe in contact with the soil.	The current project schedule is to start and complete secondary containment on both tanks between the 4th quarter of 2006 and the first quarter of 2007. All piping changes are expected to be started and completed within the second quarter of 2007.
Crystal River	3	#2	Crystal River South has one No. 2 oil (diesel fuel) tank that is within a concrete secondary containment. This tank must be upgraded per 62-761.510(3)(d) Table AST W (1) to install secondary containment. There is no pipe in contact with the soil.	Scheduled start date is September 2003; scheduled completion is December 2003.
DeBary	1	#23	DeBary tank #23 is a No. 2 oil (diesel fuel) tank that is subject to 62-761.510(3)(d) Table AST U (1) to install secondary containment and to 62-761.510(3)(d) Table AST U (2)(a) to double wall pipe in contact with soil.	Work is scheduled to be started and completed during the second quarter of 2005.
Intercession City	2	#17, #18	Intercession City tanks #17 and #18 are No. 2 oil tanks that are subject to 62-761.510 (3)(d) Table AST U (1) to install secondary containment and to 62-761.510(3)(d) Table AST U (2)(a) to double wall pipe in contact with the soil.	Double-bottoming work will be initiated and completed for tank #18 during the first quarter of 2005. Tank #17 will be upgraded during the second quarter of 2006. All piping work will be performed during the second quarter of 2006.
Rio Pinar	1	#2	Rio Pinar tank #2 is a No. 2 oil tank that is within a concrete secondary containment and is subject to the upgrade required by 62-761.510 (3)(d) Table AST W (1) to install secondary containment. There is no pipe in contact with the soil.	The schedule for this work is flexible, but will be completed by the established deadline.

Progress Energy Aboveground Storage Tank Compliance Upgrades Included in ECRC Petition				
SSuwannee	1	$24	Suwannee tank #24 contains No. 2 oil (diesel fuel), and is subject to 62-761.510 (3) (d) Table AST U (1) to install secondary containment; and, to 62-761.510 (3)(d) Table AST U (2)(a) to double wall pipe in contact with the soil.	All work is scheduled to begin and be completed during the fourth quarter of 2005.
Turner	1	#2	Turner tank #2 is a No. 2 oil (diesel fuel) tank subject to 62-761.510(3)(d) Table AST U (1) to install secondary containment. No piping will be in contact with the soil; therefore, 62-761.510(3)(d) Table AST U (2) does not apply.	Preparation work began at this site in July 2003, and will be completed by the end of 2003.
University of Florida	1	#3	University of Florida tank #3 is a No. 2 oil (diesel fuel) tank that is subject to 62-761.510 (3)(d) Table AST U (1) to install secondary containment. There is no pipe in contact with the soil.	This work is scheduled to be started and completed during the third quarter of 2006.