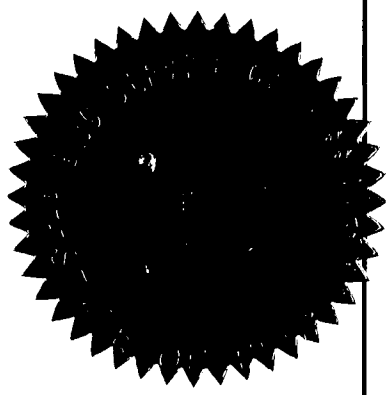
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070007-EI

In the Matter of

ENVIRONMENTAL COST RECOVERY CLAUSE.
_____/



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VOLUME 2
Pages 147 through 278

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN LISA POLAK EDGAR COMMISSIONER MATTHEW M. CARTER, II COMMISSIONER KATRINA J. McMURRIAN COMMISSIONER NANCY ARGENZIANO COMMISSIONER NATHAN A. SKOP
DATE:	Tuesday, November 6, 2007
TIME:	Commenced at 9:56 a.m. Concluded at 10:06 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, CRR, RPR Official FPSC Reporter (850) 413-6734
PARTICIPATING:	(As heretofore noted.)

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JOSEPH MCCALISTER

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 070007-EI

AUGUST 3, 2007

Q. Please state your name and business address.

A. My name is Joseph McCallister. My business address is 410 South Wilmington Street, Raleigh, North Carolina 27601.

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

A. I am employed by Progress Energy Carolinas in the capacity of Director, Gas & Oil Trading.

Q. What are your responsibilities in that position?

A. I am responsible for the procurement of natural gas, fuel oil and emission allowances on behalf of Progress Energy Florida (PEF).

Q. Please describe your educational background and professional experience.

A. I have a Bachelor of Science in Business Administration majoring in Accounting from the Ohio State University in 1987. I joined Progress Energy

Service Company LLC in November 2003. Prior to my current position, I served as Director of Portfolio and Market Risk Assessment in the Enterprise Risk Management Group. Subsequent to my tenure with Progress Energy, I spent approximately 10 years in various positions at energy based companies. Previous management experiences include gas and power scheduling, integration and commercial optimization of generation, fuel, gas storage and contracts, and corporate planning.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to outline PEF's overall procurement approach for emission allowances.

Q. What is PEF's emission procurement strategy for meeting emission allowance requirements?

A. PEF's overall procurement strategy for meeting emission allowance requirements is to buy allowances based on forecasted needs to comply with existing and future compliance requirements. PEF believes a procurement strategy of buying emission allowances over time is a reasonable and prudent approach to manage compliance requirements, reduce price risk and volatility, and provide greater price certainty for our customers.

Q. [redacted]

[redacted]

A. [redacted]

[redacted]

A. [redacted]

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Q. [redacted]

A. [redacted]

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Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

MARITZA N. IACONO

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 070007-EI

AUGUST 3, 2007

Q. Please state your name and business address.

A. My name is Maritza Iacono. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

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

A. I am employed by Progress Energy Service Company, LLC, as Supervisor of Regulatory Planning Projects.

Q. What are your responsibilities in that position?

A. I am responsible for managing all regulatory compliance filings and reporting requirements that support major construction projects.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of South Florida in 1997 with a Bachelor's Degree in Finance and from Nova Southeastern University in 1999 with a

Masters of Business Administration. Prior to joining the company in 2001, I was employed at GTE Data Services and PriceWaterhouseCoopers in budgeting functions. I began my employment with Progress Energy in 2001. During my six years I have held various positions within Energy Delivery Services and Regulatory. Just recently, I became Supervisor, Regulatory Planning Projects.

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 2007 through December 2007.

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

A. Yes. I am sponsoring the following exhibits:

1. Exhibit No. __(MI-1), which consists of PSC Forms 42-1E through 42-8E;
2. Exhibit No. __(MI-2), which provides details of four capital projects by site; and
3. Exhibit No. __(MI-3), which provides details to support the credit to revenue requirements that is being calculated for the Modular Cooling Towers project.

These forms provide a summary and detail of the Estimated/Actual True-up O&M and Capital Environmental costs and revenue requirements for the period January 2007 through December 2007.

Q. What is the Estimated/Actual True-up amount for which PEF is requesting recovery for the period of January 2007 through December 2007?

A. The Estimated/Actual True-up amount for 2007 is an under-recovery, including interest, of $3,333,530 as shown in Exhibit No. __ (MI-1), Form 42-1E, Line 4. This amount will be added to the final true-up over-recovery of $2,446,714 for 2006 shown on Form 42-2E, Line 7-a., resulting in a net under-recovery of $886,816 as shown on Form 42-2E, Line 11. The detailed calculations supporting the estimated true-up for 2007 are contained in Forms 42-1E through 42-8E.

Q. Are any of the costs listed in Forms 42-1E through 42-8E attributable to Environmental Compliance projects that have not previously been approved by the Commission?

A. No.

Q. How do the Estimated/Actual project expenditures for January 2007 through December 2007 compare with original projections?

A. As shown on Form 42-4E, total O&M project costs are projected to be $1,530 lower than originally projected. Total recoverable capital investments itemized

on Form 42-6E, are projected to be $779,406 or 58% higher than originally projected. Below are variance explanations for those approved 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 on Form 42-8E, pages 1 through 13.

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

Project revenue requirements are estimated to be $2,276,442 or 52% higher than previously projected. This variance is primarily attributable to an increase in the amount of subsurface contamination that is being encountered during remediation of substations that was not evident during the original visual environmental inspections.

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

Project revenue requirements are estimated to be $1,010,677 or 6% higher than previously projected. This variance is primarily attributable to a higher number of sites being remediated in 2007 than were originally anticipated in the 2007 work plan, including carryover from the 2006 work plan. This project is further discussed in Lisa Lohss's testimony.

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

Project revenue requirements are estimated to be $511,427 or 185% higher than previously projected. This variance is primarily attributable to work that was not completed from the 2006 workplan being carried over into 2007. This project is further discussed in Patricia Q. West's testimony.

4. Pipeline Integrity Management Program (Project #3a) – Capital

Project revenue requirements are $53,415 or 12% lower than projected because capital expenditures are being incurred later in the year than anticipated and costs are estimated to be $19,741 lower than originally projected. This will result in a decrease in the return on investment, depreciation, and property taxes. This is being offset by an adjustment to property taxes. This project is further discussed in Patricia Q. West's testimony.

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

SO2 expenses are estimated to be $2,429,068 or 21% lower than originally projected. This variance is primarily being driven by lower projected tons of emissions. The decrease in tons is attributable to lower SO2 content in fuel, as well as lower energy requirements than projected.

6. Emissions Allowances (Project #5) – Capital

The revenue requirements on the inventory of SO2 and NOx emission allowances are estimated to be $852,638 higher than originally projected. This variance is primarily driven by two factors. The first is a higher SO2 allowance inventory balance as SO2 emissions have been lower than projected and fewer allowances have been used. The second factor is that the Company has begun to build an inventory of NOx allowances in order to comply with the new requirements under CAIR beginning in 2009. The NOx procurement activity is discussed further in the testimony of Joseph McCallister.

6. Phase II Cooling Water Intake (Project #6) – O&M

Project revenue requirements are estimated to be $931,199 or 66% lower than originally forecasted. This variance is primarily attributable to a reduction in study costs due to the suspension of the EPA rule governing this project. This project is further discussed in Patricia Q. West's testimony.

7. CAIR/CAMR (Project #7) – Capital

Project revenue requirements are estimated to be $22,803 or 11% lower than originally projected. This variance is primarily attributable to schedule delays at Anclote which have reduced the overall revenue requirements because there is an overall lower capital balance on which a return is being

earned, offset by the acceleration of work on the Combustion Turbine (CT) projects.

Capital expenditures for the Crystal River are projected to be approximately $85.3 million higher than originally projected primarily due to contract negotiations which includes further refinement of scope changes as well as price escalations. This project has no bearing on the ECRC recoverable balance because it is accruing AFUDC. These projects are further discussed in Patricia Q. West's testimony.

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

Project revenue requirements are estimated to be $69,616 or 90% lower than originally forecasted. This variance is due to the work being postponed until finalization of a compliance plan and schedule with FDEP. This project is further discussed in Patricia Q. West's testimony.

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

Project revenue requirements are estimated to be $352,422 or 74% lower than originally forecasted. This variance is primarily attributable to a delay in the next phase of our research study. This study, which is to be conducted by the University of Florida, is designed to further our understanding of the light spectrum which will be used to identify new and/or emerging lighting

technologies that provide additional options for ensuring compliance with applicable sea turtle ordinances and criteria.

10. Sea Turtle – Coastal Street Lighting (Project #9) – Capital

Project revenue requirements are estimated to be $41,943 or 98% lower than originally forecasted. This variance is primarily attributable to a delay in the capital portion of this project pending completion of further studies with the University of Florida.

11. Underground Storage Tanks (Project #10) – Capital

Project revenue requirements for 2006 are estimated to be $16,048 or 28% lower than originally forecasted because PEF projected a commercial in-service date which was delayed and an adjustment for removal costs of the original asset that were incorrectly included as part of the asset installation costs. This project is further discussed in Patricia Q. West's testimony.

12. Modular Cooling Towers (Project #11) – Capital

Project revenue requirements for 2007 are estimated to be $70,596 or 49% higher than originally forecasted primarily due to additional costs that were incurred for the installation of two new permanent breakers. In addition, the revenue requirements includes a credit of $8,082.75 that PEF has reflected to account for the depreciation expense, return and property taxes that are

presently being recovered through base rates for the retired assets. The calculation of this credit is shown on Exhibit No. __(MI-3).

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

MARITZA N. IACONO

ON BEHALF OF

PROGRESS ENERGY FLORIDA

DOCKET NO. 070007-EI

August 31, 2007

Q. Please state your name and business address,

A. My name is Maritza N. Iacono. My business address is 299 First Avenue North, St. Petersburg, FL 33701.

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

A. I am employed by Progress Energy Service Company, LLC, as Supervisor of Regulatory Planning Projects.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, Progress Energy Florida's calculation of the revenue requirements and its Environmental Cost Recovery ("ECRC") factors for application on customer billings during the period January 2008 through December 2008. My testimony addresses the capital and operating and maintenance ("O&M") expenses associated with PEF's environmental compliance activities for the year 2008.

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

A. Yes. I am sponsoring the following exhibits:

1. Exhibit No. __ (MI-4), which consists of PSC Forms 42-1P through 42-7P; and
2. Exhibit No. __MI-5, which provides details of three capital projects by site.

Q. What is the total recoverable revenue requirement relating to the projection period January 2008 through December 2008?

A. The total recoverable revenue requirement including true-up amounts and revenue taxes is $44,123,551 as shown on Form 42-1P, Line 5 of Exhibit No. __ (MI-4).

Q. What is the total true-up to be applied in the period January 2008 through December 2008?

A. The total true-up applicable for this period is an under-recovery of $886,816. This consists of the final true-up of $2,446,714 for the period from January 2006 through December 2006 and an estimated true-up under-recovery of $3,333,530 for the current period of January 2007 through December 2007. The detailed calculation supporting the estimated true-up was provided on Forms 42-1E through 42-8E of Exhibit No. __ (MI-1) filed with the Commission on August 3, 2007.

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

A. Yes. PEF's 2007 ECRC projections include the following projects that have been previously approved by the Commission:

The Clean Air Interstate Rule ("CAIR") and the Clean Air Mercury Rule ("CAMR") Program (No. 7) was previously approved as an ECRC recoverable project in Order No. PSC-05-1251-FOF-EI. PEF submitted it's Integrated Clean

Air Compliance Plan on March 31, 2006 in Docket No. 060007-EI. In addition, PEF submitted an updated Plan and supporting analyses in this docket on June 1, 2007.

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

The Pipeline Integrity Management Program (No. 3) and the Above Ground Tank Secondary Containment Program (No. 4) were previously approved in Order No. PSC-03-1230-PCO-EI.

The recovery of SO_2 Emission Allowances (No. 5) was previously approved in Order No. PSC-95-0450-FOF-EI; however, the costs were moved to the ECRC Docket from the Fuel Docket beginning January 1, 2004 at the request of Staff to be consistent with the other Florida IOUs.

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

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

The Modular Cooling Tower Program (No. 11) was previously approved by Commission vote on August 14, 2007, in Docket 060162.

Q. Have you prepared schedules showing the calculation of the recoverable O&M project costs for 2008?

A. Yes. Form 42-2P contained in Exhibit No. __ (MI-4) summarizes the recoverable O&M cost estimates for these projects in the amount of $36,518,979.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2008?

A. Yes. Form 42-3P contained in Exhibit No. __ (MI-4), summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 13, shows the calculations of these costs that result in recoverable jurisdictional capital costs of $6,686,010.

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 11, contained in Exhibit No. __ (MI-4) provides each project description and progress, as well as the projected recoverable cost estimates.

Q. What is the total projected jurisdictional costs for environmental compliance activities in the year 2008?

A. The total jurisdictional capital and O&M costs of $44,091,805 to be recovered through the ECRC, are calculated on Form 42-1P, contained in Exhibit No. __ (MI-4).

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

A. The ECRC factors were calculated as shown on Forms 42-6P and 42-7P contained in Exhibit No. __ (MI-4). 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 2007 load research study. Form 42-7P presents the calculation of the proposed ECRC billing factors by rate class.

Q. What are Progress Energy Florida's proposed 2008 ECRC billing factors by the various rate classes and delivery voltages?

A. The computation of Progress Energy Florida's proposed ECRC factors for customer billings in 2008 is shown on Form 42-7P, contained in Exhibit No. __ (MI-4). In summary, these factors are as follows:

RATE CLASS	ECRC FACTORS
Residential	0.118 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.109 cents/kWh
@ Primary Voltage	0.108 cents/kWh
@ Transmission Voltage	0.107 cents/kWh
General Service 100% Load Factor	0.081 cents/kWh
General Service Demand	
@ Secondary Voltage	0.094 cents/kWh
@ Primary Voltage	0.093 cents/kWh
@ Transmission Voltage	0.092 cents/kWh
Curtailable	
@ Secondary Voltage	0.090 cents/kWh
@ Primary Voltage	0.089 cents/kWh
@ Transmission Voltage	0.088 cents/kWh
Interruptible	
@ Secondary Voltage	0.079 cents/kWh
@ Primary Voltage	0.078 cents/kWh
@ Transmission Voltage	0.077 cents/kWh
Lighting	0.094 cents/kWh

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

A. PEF is requesting that its proposed ECRC billing factors be made effective with the first bill group for January 2008 and continue through the last bill group for December 2008.

Q. Please summarize your testimony.

A. My testimony supports the approval of an average environmental billing factor of 0.106 cents per kWh which includes projected capital and O&M revenue requirements of $44,091,805 associated with a total of 11 environmental projects and a true-up under-recovery provision of $886,816. My testimony also demonstrates that the projected environmental expenditures for 2008 are appropriate for recovery through the ECRC.

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. 070007-EI
April 2, 2007

Q. Please state your name and business address.

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

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

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

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

A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science Degree in Marine Biology. I also hold a Bachelor's Degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Masters of Science Degree in Management from Troy State University, Pensacola, Florida. In August 1978, I joined Gulf Power Company as an Associate Engineer and have since held various engineering positions with increasing responsibilities such as Air Quality Engineer, Senior Environmental Licensing Engineer, and Manager of Environmental Affairs. In 2003, I assumed my present position as Director of Environmental Affairs.

Q. What are your responsibilities with Gulf Power Company?

A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs area to ensure the Company is, and remains, in compliance with environmental laws and regulations, i.e. both existing laws and such laws and regulations that may be enacted or amended in the future. In performing this function, I am responsible for numerous environmental activities.

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

A. Yes.

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

A. The purpose of my testimony is to support Gulf Power Company's true-up for the period from January 1, 2006 through December 31, 2006.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the final true-up calculation for the period January 2006 through December 2006 with the approved estimated true-up amounts.

A. As reflected in Ms. Martin's Schedule 6A, the recoverable capital costs included in the estimated true-up total $29,694,980, as compared to the actual recoverable capital costs of $30,031,688. This results in a variance of $336,708 or 1% above the estimated true-up. I will address five projects that contribute to this variance: the Crist DEP Project, Crist Stormwater Collection System, Crist Water Conservation Project, Crist Condenser Tubes, and SO_2

Allowances.

Q. Please explain the capital project variance of 2% or $414,973 in the Crist DEP Project (Line Item 1.19).

A. The Crist DEP Project deviation primarily resulted from an increase in the dismantlement accrual for Plant Crist associated with the addition of the Crist Unit 7 selective catalytic reduction (SCR). Gulf's cost estimates for dismantlement for Plant Crist were approved in FPSC Order No. PSC-06-0348-PAA-EI issued April 24, 2006, in Docket No. 050381-EI. The implementation date of the new dismantlement provisions was January 1, 2006; therefore, a retroactive adjustment was made to the Company's books in July 2006. The 2006 estimated true-up filing was based on actual dollars booked through June and, therefore, did not include the adjustment made to the books in July. The Crist DEP Project line item now reflects the dismantlement accrual associated with the Crist Unit 7 SCR for the period January through December 2006.

Q. Please explain the (23%) variance of ($9,018) for Crist Stormwater Collection System (Line Item 1.20).

A. Construction of the Crist Switchyard Stormwater project was delayed due to additional design modifications that were needed to connect the new stormwater sump to the existing piping system. The sump discharge structure and bottom were lowered to accommodate the existing underground stormwater piping. The delay in placing this project into service resulted in the actual depreciation expense being less than originally projected.

Q. Please explain the (56%) variance of ($1,833) in the Crist Water Conservation Project (Line Item 1.24).

A. The Crist Water Conservation project included the installation of automatic level controls on the plant's fire water tanks to reduce groundwater usage. The project was postponed several months while Gulf considered relocating the fire tanks, which resulted in a delay in spending and the project was placed in-service one month later than originally anticipated. This delay in spending resulted in actual capital costs being less than estimated.

Q. Please explain the capital project variance of ($69,489) or (9%) in the Crist Condenser Tubes (Line Item 1.25).

A. The variance in Line Item 1.25, Crist Condenser Tubes, is primarily due to a delay in the release of the retainage payment due under the contract. Gulf is holding this retainage until the project is completed. The Crist Unit 6 condenser is currently in service; however, the vendor has not completed all of its contracted work. Due to schedule delays, the outlet waterbox coatings were not installed. The remaining work has been planned for the Fall of 2007 outage.

Q. Please explain the capital variance of $37,713 or 6% in SO_2 Allowances (Line Item 1.26).

A. The SO_2 Allowance variance was due primarily to a higher allowance inventory than originally projected, which resulted in higher carrying costs. Fewer allowances were surrendered in the period than had been budgeted because more low sulfur coal was purchased than was originally anticipated.

Q. How do the actual O&M expenses for the period January 2006 to December 2006 compare to the estimated true-up?

A. Ms. Martin's Schedule 4A reflects that Gulf's recoverable environmental O&M expenses for the current period were $8,629,958, as compared to the estimated true-up of $10,612,425. This results in a net variance of $1,982,467 or 19% below the estimated true-up. I will address six O&M projects and programs that contribute to this variance -- Title V, General Water Quality, Groundwater Contamination Investigation, Above Ground Storage Tanks, FDEP NO_X Reduction Agreement and SO_2 Allowances.

Q. Please explain the (24%) variance of ($17,614) in Title V (Line Item 1.3).

A. Gulf Power submitted Title V permit renewal applications for Plants Crist, Smith, and Scholz during 2004. The revised permits became effective on January 1, 2005. The 2006 permit implementation costs were less than originally anticipated.

Q. Please explain the variance of ($130,579) or (25%) in the category General Water Quality (Line Item 1.6).

A. The General Water Quality variance primarily resulted from reducing the scope of the surface water studies and postponing portions of the plant groundwater investigation projects. The number of samples collected during the 2006 surface water studies was reduced resulting in lower sampling and laboratory charges. The Plant Scholz groundwater investigation project was delayed while Gulf awaited the Florida Department of Environmental Protection's response to the groundwater study.

Q. Please explain the (7%) variance of ($80,078) in the category Groundwater Contamination Investigation (Line Item 1.7).

A. The Shalimar substation excavation activities were not conducted during 2006 because underground utilities were located within the proposed excavation area. Gulf is currently working with the property owner to obtain approval to revise the remediation and excavation plan to include setbacks from the underground utilities.

Q. Please explain the variance of ($74,840) or (78%) in the category entitled Above Ground Storage Tanks (Line Item 1.12).

A. Plant Crist originally planned to recoat several above ground storage tank concrete secondary containment areas during 2006. After further examination, Plant Crist determined that this work could be postponed.

Q. Please explain the (10%) variance of ($208,603) in Line Item 1.19, FDEP NO_X Reduction Agreement.

A. This O&M line item includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the FDEP NO_X Reduction Agreement. The anhydrous ammonia and urea expenses are dependent on the available coal supply, unit load, and market value. The price of anhydrous ammonia and urea was less than projected in the estimated true-up filing. In addition, less urea was required for the operation of the selective non-catalytic reduction (SNCR) system than originally anticipated.

Q. Please explain the variance of ($1,459,510) or (31%) in SO_2 Allowances (Line Item 1.20).

A. The SO_2 Allowance variance resulted from burning lower sulfur coal. More low sulfur coal was purchased from the spot market than was originally anticipated and, therefore, fewer allowances were surrendered in the period than had been budgeted.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James O. Vick
Docket No. 070007-EI
August 3, 2007

Q. Please state your name and business address.

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

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

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

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

A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science Degree in Marine Biology. I also hold a Bachelor's Degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Masters of Science Degree in Management from Troy State University, Pensacola, Florida. I joined Gulf Power Company in August 1978 as an Associate Engineer. I have since held various engineering positions with increasing responsibilities such as Air Quality Engineer and Senior Environmental Licensing Engineer. In 2003, I assumed

my present position as Director of Environmental Affairs.

Q. What are your responsibilities with Gulf Power Company?

A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs section to ensure the Company is, and remains, in compliance with environmental laws and regulations, i.e., both existing laws and such laws and regulations that may be enacted or amended in the future. In performing this function, I am responsibile for numerous environmental activities.

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

A. Yes.

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

A. The purpose of my testimony is to support Gulf Power Company's estimated true-up for the period from January 1, 2007 through December 31, 2007. This true-up is based on six months of actual data and six months of estimated data.

Q. Mr. Vick, please compare Gulf's recoverable environmental capital costs included in the estimated true-up calculation for the period January 1, 2007 through December 31, 2007 with approved projected amounts.

A. As reflected in Ms. Martin's Schedule 6E, the recoverable capital costs approved in the original projection total $36,627,609, as compared

to the estimated true-up amount of $33,857,505. This results in a projected variance of ($2,770,104). There are eight capital projects and programs that contributed to the majority of this variance: Crist 5, 6, & 7 Precipitator Projects; Smith Stormwater Collection System; Crist FDEP Agreement for Ozone Attainment; Crist Stormwater Collection System; Plant Groundwater Investigation; Crist Condenser Tubes; CAIR/CAMR/CAVR Compliance Program, and finally, SO_2 allowances. The variances for these projects are discussed below.

Q. Please explain the capital project variance of ($105,629) in Crist 5, 6 & 7 Precipitator Projects (Line Item 1.2).

A. The Crist Precipitator Projects, Line Item 1.2, deviation resulted from a decrease in the dismantlement accrual and depreciation rate for Plant Crist. Gulf's revised depreciation rates and dismantlement accruals were approved in FPSC Order No. PSC-07-0012-PAA-EI issued January 2, 2007, in Docket No. 050381-EI. The implementation date of the new depreciation rates and dismantlement accruals was January 1, 2007. The 2007 projection filing was based on depreciation rates approved in FPSC Order No. PSC-06-0348-PAA-EI that became effective on January 1, 2006.

Q. Please explain the variance of ($36,760) in the capital category entitled Smith Stormwater Collection System (Line Item 1.14).

A. The variance in Line Item 1.14, Smith Stormwater Collection System, is primarily due to a decrease in the depreciation rate for Plant Smith. Gulf's amended depreciation rates were approved in FPSC Order No. PSC-07-

0012-PAA-EI issued January 2, 2007, in Docket No. 050381-EI. The implementation date of the new depreciation rates was January 1, 2007. The 2007 projection filing was based on depreciation rates approved in FPSC Order No. PSC-06-0348-PAA-EI that became effective on January 1, 2006.

Q. Please explain the variance of ($913,605) in the capital category entitled Crist FDEP Agreement for Ozone Attainment (Line Item 1.19).

A. The variance in the FDEP Agreement line item is primarily due to the decrease in the dismantlement accrual and depreciation rate for Plant Crist. The Crist Unit 6 SCR catalyst retirement was also greater than originally anticipated. Gulf projected that a half layer of catalyst would need to be retired; however, a complete layer was replaced.

Q. Please explain the $34,393 variance in Crist Stormwater Collection System (Line Item 1.20).

A. Construction of the Crist Switchyard Stormwater project was delayed during 2006 due to additional design modifications that were needed to connect the new stormwater sump to the existing piping system. The sump discharge structure and bottom were lowered to accommodate the existing underground stormwater piping. These design modifications increased the total project cost, resulting in a higher beginning of period investment balance than originally anticipated. The delays also resulted in expenditures carrying over into 2007 that were not projected.

Q. Please explain the ($24,082) variance in the Plant Groundwater Investigation (Line Item 1.23).

A. The Line Item 1.23 variance resulted from postponing the Plant Scholz Groundwater Investigation project and canceling the Plant Crist project. The Plant Scholz project has been delayed until Gulf receives Florida Department of Environmental Protection's formal response to the Plant Scholz groundwater study. The Plant Crist project has been removed from the 2007 projection because Gulf has been released from any remedial action at this site.

Q. Please explain the ($290,590) variance in Crist Condenser Tubes (Line Item 1.25).

A. The variance in Line Item 1.25, Crist Condenser Tubes, is primarily due to a lower beginning of period investment balance than originally projected. The 2006 expenditures were less than Gulf projected in the 2006 Estimated True-Up filing because charges for additional repair work required in conjunction with the condenser tube installation were lower than expected. In addition, Plant Crist's revised depreciation rate approved in FPSC Order No. PSC-07-0012-PAA-EI issued January 2, 2007 was lower than the rate included in the 2007 projection filing.

Q. Please explain the ($1,265,943) variance in the CAIR/CAMR/CAVR Compliance Program (Line Item 1.26).

A. The variance in the CAIR/CAMR/CAVR Compliance Program is primarily due to the cost of the Unit 7 cooling tower relocation being less than originally

anticipated, the Crist 7 cooling tower being included in the Environmental Cost Recovery Clause beginning in June 2007 rather than in May 2007 as originally projected, and delays in the Plant Smith Selective Non-Catalytic Reduction (SNCR) projects. The Crist Unit 7 Cooling Tower expenditures were approximately 11% less than Gulf's initial cost projection because the successful bid to furnish and erect the tower was less than expected. The original budgetary estimate was based on the cost of similar cooling tower installations. Engineering and design for the Plant Smith SNCRs will begin during 2007, although Gulf will not begin receiving materials during 2007 as originally planned. The actual cost to relocate sections of existing transmission lines was also less than originally projected. The 2007 budget for the transmission line relocations was based on a conservative estimate provided prior to completing the project design.

Q. Please explain the ($140,871) variance in SO_2 Allowances in Line Item 1.28.

A. The average net working capital balance for the SO_2 Allowances project was lower than anticipated, resulting in a lower return on working capital, because more allowances were surrendered due to burning a higher sulfur coal.

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

A. Ms. Martin's Schedule 4E reflects that Gulf's recoverable environmental O&M expenses for the current period are now estimated to be $17,849,512 as compared to the original projection of $13,246,963. This will result in a year-end variance of $4,602,549. There are six O&M projects and programs that

contributed to the majority of this variance that I will discuss: Emission Monitoring; General Water Quality; General Solid and Hazardous Waste; Sodium Injection; FDEP NOx Reduction Agreement; and SO_2 Allowances.

Q. Please explain the ($99,692) variance in Emission Monitoring (Line Item 1.5).

A. The emission monitoring maintenance and relative accuracy test audit (RATA) expenses were less than originally projected. Fewer RATA tests were required than originally expected. In addition, the 2006 maintenance contract was extended for one year at the current rate which reduced the 2007 maintenance expenses from the original projection that had assumed an increase in the rate.

Q. Please explain the variance of ($141,066) in the category entitled General Water Quality (Line Item 1.6).

A. The General Water Quality variance primarily resulted from delaying portions of the Cooling Water Intake Program and reducing the Surface Water Sampling Program O&M expenses. The scope of Gulf's 2007 Cooling Water Intake Program biological sampling and data collection plan was reduced after EPA's March 2007 announcement that the rule it adopted pursuant to Section 316(b) of the Clean Water Act should be considered suspended. Gulf's expenses associated with the surface water sampling studies were also lower than originally projected because Gulf was able to conduct a larger portion of these studies in-house than was expected at the time our projection was prepared.

Q. Please explain the variance of $67,505 in General Solid and Hazardous Waste (Line Item 1.11).

A. This variance resulted from waste removal and disposal costs for Plant Crist and Plant Smith being more than originally anticipated. Both plants conducted source removal and assessment activities during the January to June 2007 period in response to releases from registered aboveground storage tanks. The amount of solid and hazardous waste generated varies from one period to the next.

Q. Please explain the variance of ($63,469) in Sodium Injection (Line Item 1.16).

A. The expenses that Gulf incurs for this program are dependent on the available coal supply and the necessity for sodium injection. The need for sodium injection was less than what was anticipated for Plants Crist and Smith during the January through June 2007 period because the coal supply had a higher sodium content than originally projected.

Q. Please explain the variance of ($100,267) in Line Item 1.19, FDEP NOx Reduction Agreement.

A. The FDEP NOx Reduction Agreement (Line Item 1.19) includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the Plant Crist FDEP Agreement for Ozone Attainment. The variance in this line item is primarily due to anticipated reductions in the amount of chemical usage as a result of the units being out of service during the Fall 2007 maintenance outages.

Q. Please explain the $4,914,009 variance in SO_2 allowances in Line Item 1.20.

A. The January through June 2007 SO_2 Allowance variance resulted from burning higher sulfur coal. Less low sulfur coal was purchased than originally anticipated and, therefore, more allowances were surrendered in the period than had been projected. Gulf expects to continue burning a higher sulfur coal, causing more allowances to be utilized than originally projected for the remainder of 2007.

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. 070007-EI

August 31, 2007

Q. Please state your name and business address.

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

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

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

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

A. I graduated from Florida State University, Tallahassee, Florida, in 1975 with a Bachelor of Science Degree in Marine Biology. I also hold a Bachelor's Degree in Civil Engineering from the University of South Florida in Tampa, Florida. In addition, I have a Masters of Science Degree in Management from Troy State University, Pensacola, Florida. I joined Gulf Power Company in August 1978 as an Associate Engineer. I have since held various engineering positions with increasing responsibilities such as Air Quality Engineer, Senior Environmental Licensing Engineer, and Manager of Environmental Affairs. In 2003,

I assumed my present position as Director of Environmental Affairs.

Q. What are your responsibilities with Gulf Power Company?

A. As Director of Environmental Affairs, my primary responsibility is overseeing the activities of the Environmental Affairs section to ensure the Company is, and remains, in compliance with environmental laws and regulations, i.e., both existing laws and such laws and regulations that may be enacted or amended in the future. In performing this function, I have the responsibility for numerous environmental activities.

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

A. Yes.

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

A. The purpose of my testimony is to support Gulf Power Company's projection of environmental compliance costs recoverable through the Environmental Cost Recovery Clause (ECRC) for the period from January 2008 through December 2008.

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

A. The environmental capital projects for which Gulf seeks recovery through the ECRC are described in Schedules 3P, 4P, and 5P attached to the Company's petition in this docket. The exhibits attached to the petition

have been incorporated into hearing exhibits that are being sponsored in this proceeding by Ms. Martin. I am supporting the expenditures, clearings, retirements, salvage and cost of removal currently projected for each of these projects and the monthly costs for emission allowances. Ms. Martin compiled these schedules and has calculated the associated revenue requirements for Gulf's requested recovery.

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

A. No. Gulf's 2008 ECRC capital projection includes (1) projects that have been previously approved by the Commission, (2) additional expenditures associated with projects previously approved by the Commission and (3) new projects.

Q. Mr. Vick, please describe the capital projects included in Gulf's CAIR/CAMR/CAVR Compliance Program that will impact the 2008 projected ECRC revenue requirements.

A. For the purpose of the 2008 projection of ECRC revenue requirements, expenditures totaling $23.5 million are projected to be incurred for capital projects included in the CAIR/CAMR/CAVR Compliance Program. These capital projects include installing Activated Carbon Injection (ACI) at Plant Daniel on Unit 2, Low NO_x burners at Plant Daniel on Units 1 and 2, Selective Non-Catalytic Reduction (SNCR) technologies at Plant Smith on Units 1 and 2, and mercury monitoring equipment. As I will discuss later in my testimony, ACI has been added to Gulf's Compliance Program for

mercury control at Plant Daniel beginning in 2010.

The Daniel Low NO_x burners and Smith SNCRs are needed for Phase I Clean Air Interstate Rule (CAIR) annual and seasonal NO_x cap and trade allowance programs. In addition, NO_x reductions from these projects will help in maintaining local compliance with the 8-hour ozone standard.

As I previously discussed in my 2007 estimated/actual true-up testimony, portions of the Plant Smith SNCR projects have been delayed from 2007 to 2008. Engineering and design for the SNCRs will occur during 2007 as previously projected. Gulf will not begin receiving materials during 2007 as originally planned. The receipt of materials is not expected until 2008. The Daniel Unit 2 Low NO_x burners are expected to be placed in service during December of 2008.

The Clean Air Mercury Rule (CAMR) will require continuous emission monitoring of mercury emissions at all of Gulf's coal-fired units and the Plant Crist scrubber. Mercury monitors will be installed during 2008 on all of Gulf's coal-fired units excluding Plant Crist. Mercury monitors will be installed on the Plant Crist scrubber during 2009.

The Plant Crist Units 4 through 7 mercury monitors that were previously scheduled to be placed in service during 2008 have been removed from the current projection. These monitors are no longer required because EPA approved Gulf's petition for an extension of the deadline for installation of mercury monitors on the existing stacks until after the scrubber is completed. The granting of this petition eliminated the need for the plant to install four mercury monitors that would only be

needed from January 1, 2009 until the completion of the scrubber later in 2009.

In 2008, installation of mercury monitoring equipment is also planned for Gulf's relative accuracy testing audit (RATA) trailer. This system will be used to subject the mercury monitors to rigorous quality assurance measures in order to ensure accurate accounting of mercury emissions.

Q. Mr. Vick, are there additional capital expenditures projected in 2008 for ECRC projects/programs that have been previously approved by the Commission?

A. Yes. There are six additional projects that have projected capital expenditures during 2008. Four of the projects are related to Gulf's existing Air Quality programs: Crist 5, 6, & 7 Precipitator Upgrades, Continuous Emission Monitoring (CEMs) replacements, Plant Crist FDEP Agreement for Ozone Attainment, and Precipitator Upgrades for Compliance Assurance Monitoring (CAM) Compliance. The Daniel Ash Management project and the Plant NPDES Compliance Projects also have projected expenditures in 2008.

Q. Mr. Vick, please describe the expenditures included in the 2008 projection for the Crist 5, 6, & 7 Precipitator Upgrades (Line 1.2).

A. The Plant Crist Unit 6 and Unit 7 precipitator upgrades were originally undertaken in the early 1990's and approved for environmental cost recovery in Docket No. 930613-EI. These upgrades were required and

continue to be needed to comply with the Clean Air Act Amendments (CAAA) of 1990. During the 2008 recovery period, Plant Crist plans to install a new purge air system on the Unit 6 precipitator to ensure that the insulators continue functioning properly in order to maintain compliance with the CAAA. The 2008 projected expenditures for the purge air system are $500,000.

Q. Mr. Vick, please describe the projects included in the 2008 projection for Continuous Emission Monitoring (Line 1.5).

A. During the 2008 recovery period, the CEMs project includes the replacement of opacity, flow, and gas monitors at Plant Smith and opacity and gas monitors at Plant Scholz. Opacity monitors are needed to maintain compliance with the CAAA requirements. Flow and gas monitors are necessary in order to provide the accuracy and reliability needed to measure SO_2 and NO_x for compliance with Chapter 40 CFR Part 75 under the Acid Rain Program. The Plant Smith CEMs replacements were originally projected to be placed in-service during December of 2007; however, this project has been delayed while Gulf evaluates the feasibility of moving the monitoring location from the air ducts to the stack. The existing monitors at Plants Smith and Scholz are approaching the end of their useful lives and will be retired upon replacement. The 2008 expenditures are expected to be approximately $1.0 million.

Q. Please describe the expenditures included in the 2008 projection for the Crist FDEP Agreement for Ozone Attainment (Line 1.19).

A. For the 2008 projection, Gulf has included additional capital costs to meet the terms of the August 28, 2002, agreement with FDEP. Gulf will be installing a new layer of the Crist Unit 7 SCR catalyst and an additional ash vibrator system to manage waste products associated with the operation of the SCR system. The addition of this layer of catalyst will allow for the maintenance of the catalyst system over time. The Crist SCR ash vibrator system is needed to ensure that the SCR hoppers can be completely emptied to prevent operational problems. The projected 2008 expenditures for the Crist FDEP Agreement project are $2.15 million.

Q. Mr. Vick, please describe the expenditures included in the 2008 projection for the Precipitator Upgrades for CAM Compliance (Line Item 1.22).

A. CAM requirements are regulated under Chapter 40 CFR Part 64 which requires a method of continuously monitoring pollution control equipment. Opacity can be used as a surrogate parameter if the precipitator demonstrates a correlation between opacity and particulate matter. Gulf demonstrated this correlation by stack testing in 2003 and 2004, and submitted the results to the FDEP as part of a CAM plan in Gulf's Title V Air Permit renewals in 2004. The Crist Units 4 and 5 precipitator upgrades that are included under this line item on Ms. Martin's schedules are necessary to meet the more stringent surrogate opacity standards under CAM. These projects were approved for environmental cost

recovery in the Commission Order resulting from the November 2006 ECRC hearing. At the time of the 2007 ECRC estimated/actual true-up filing, Gulf expected the Unit 5 precipitator upgrade to be completed during December of 2007; however, the project will not be placed in service until March of 2008 due to changes in the unit outage schedule. The Crist Unit 4 precipitator upgrade is also expected to be placed in service in March of 2008 in conjunction with the spring outage. Gulf's projected 2008 expenditures for the Plant Crist CAM precipitator upgrades are $9.6 million.

Q. Please describe the 2008 projected expenditures for the Daniel Ash Management Project (Line 1.16).

A. The FPSC granted approval for recovery of the Daniel Ash Management Project through the ECRC in Order No. PSC-94-0044-FOF-EI. During the 2005 ECRC projection filing, the project was expanded to include a new on-site ash storage facility in preparation for the completion and closure of the existing storage area. The new ash storage facility was placed in service during December of 2006. Gulf expects to incur approximately $34,000 of additional capital expenditures during 2008 to complete construction of the stormwater management system.

Q. Mr. Vick, please describe the 2008 projected expenditures for the Plant NPDES Compliance Program (Line 1.25).

A. The Plant NPDES compliance program encompasses projects necessary to meet more stringent water quality standards required by Gulf's NPDES

industrial wastewater permits. The first project related to this compliance activity was the Crist condenser tube project implemented in 2006. As shown in Ms. Martin's schedules, the line item previously titled "Crist Condenser Tubes" has been renamed "Plant NPDES Compliance Projects" to better reflect the full scope of this activity. This line item will include both the original Crist Unit 6 condenser tube project and any additional copper water treatment projects at Plant Crist related to compliance with the water quality requirements of the Plant Crist NPDES industrial wastewater permit.

For 2008, we are anticipating the need for an additional copper water treatment project as part of the Plant NPDES Compliance program that was initiated when the Crist condenser tubes project was implemented in 2006 to meet more stringent water quality standards. As has been discussed in previous testimony, the water quality-based copper effluent limitations included in Chapter 62 Part 302, Florida Administrative Code, were amended in April 2002 with an effective date of May 2002. The more stringent hardness-based standard is included by reference in the Plant Crist NPDES industrial wastewater permit. The copper limit is calculated from an equation that is dependent upon the river water hardness concentration.

Surface water studies were conducted from 2003 through 2005 to determine the source of aqueous copper in the effluent. The results of the study concluded that the Crist Unit 6 condenser was the main source of the incremental copper in the Plant Crist discharge. The condenser tubes were replaced with stainless steel condenser tubes during 2006 in

an effort to meet the revised water quality standards. Although we have eliminated the Plant Crist Unit 6 condenser tubes as the main source of aqueous copper in the discharge, Plant Crist has continued to encounter problems meeting the copper water quality standard.

Gulf is currently conducting a study to identify solutions necessary to further reduce the copper concentration. Gulf expects to incur approximately $150,000 of expenditures during 2008 to help ensure compliance with the NPDES permit water quality standards. Solutions currently being considered include chemical treatment and/or aeration of either the oil skimmer pond or ash pond.

Q. Have there been any developments regarding Gulf's CAIR/CAMR/CAVR Compliance Program that have an impact on capital projects projected for recovery during 2008?

A. Yes. Testing of ACI at Plant Daniel has demonstrated that 60-70% of the mercury emissions may be controlled through the use of ACI which is higher than typically expected when ACI is added ahead of an electrostatic precipitator as will be the case at Plant Daniel. As a result, we are now proposing to add ACI at Plant Daniel as an element of Gulf's CAIR/CAMR/CAVR Compliance Program for mercury control at Plant Daniel as part of the obligation to meet CAMR requirements beginning in 2010. Addition of ACI will serve to reduce Gulf's need to rely on an undeveloped mercury allowance market. In order to meet this time frame and take advantage of the outage schedule for Daniel Units 1 and 2, an ACI system will be installed on Daniel Unit 2 during 2008 and on Daniel

Unit 1 during 2009.

ACI involves the addition of powdered activated carbon to the flue gas stream that absorbs vapor phase mercury. The activated carbon (and absorbed mercury) is then collected in a particulate collection device. In addition to reducing Gulf's (and Mississippi's) reliance on an as yet undeveloped allowance market, the installation of ACI at Plant Daniel and the purchase of additional SO_2 allowances allow Gulf and Mississippi Power the opportunity to adjust the timing for the installation of flue gas desulfurization and selective catalytic reduction (SCR) technology at Plant Daniel in order to optimize the co-benefits of these two components with regard to mercury control. The impact of this project on the projected cost savings to the customer from retrofitting the units compared to retirement and replacement is less than five percent of the initial savings shown for Plant Daniel in Gulf's March 29, 2007 CAIR/CAMR/CAVR Compliance Plan. In other words, although the NPV savings or benefit to Gulf's customers from retrofitting Plant Daniel and continuing to operate these units as compared to the retirement replacement alternative for this capacity is reduced slightly due to the addition of ACI, this slight reduction reduces the reliance on an as yet undeveloped market for allowances and the associated risk.

Q. Mr. Vick, are you including the purchase of allowances in your 2008 projection filing?

A. No, we currently do not have plans to purchase allowances during 2008. However, Gulf's compliance strategy continues to include possible forward

contracts, swaps, and spot market purchases of allowances depending on market prices. The reasoning behind this strategy is Gulf's concern over the availability and the price of allowances as the compliance deadlines for CAIR and CAMR approach. Many utilities are no longer selling any allowances in anticipation of their own shortfalls in the coming years. Although we are not projecting any purchases during 2008 at this time, if favorable market conditions develop, we will do so.

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

A. All of the O&M activities listed on Schedule 2P have been approved for recovery through the ECRC in past proceedings, including O&M expenses associated with the approved stipulation regarding portions of Gulf's CAIR/CAMR/CAVR Compliance Program.

Q. Please describe the O&M activities included in the air quality category that have projected expenses in 2008.

A. There are five O&M activities included in the air quality category that have projected expenses in 2008. On Schedule 2P, Air Emission Fees (Line Item 1.2), represents the expenses projected for the annual fees required by the CAAA that are payable to the FDEP. The expenses projected for the recovery period total $779,874.

Included in the air quality category, Title V (Line Item 1.3) represents projected expenses associated with the implementation of the

Title V permits. The total estimated expenses for the Title V Program during 2008 are $91,571.

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 $2,250.

Emission Monitoring (Line Item 1.5) on Schedule 2P reflects an ongoing O&M expense associated with the Continuous Emission Monitoring equipment as required by the CAAA. These expenses are incurred in response to EPA's requirements that the Company perform Quality Assurance/Quality Control (QA/QC) testing for the CEMs, including Relative Accuracy Test Audits (RATAs) and Linearity Tests. Other activities within this category include the testing, development, and implementation of new compliance assurance monitoring requirements associated with the CAAA. The expenses expected to be incurred during the 2008 recovery period for these activities total $663,054.

The FDEP NO_x Reduction Agreement (Line Item 1.19) includes the O&M costs associated with the Plant Crist Unit 7 SCR and Crist Units 4 through 6 SNCR projects that were included as part of the 2002 agreement with FDEP. This O&M line item includes the cost of anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses related to the activities undertaken in connection with the agreement. Gulf was granted approval for recovery of the costs incurred to complete these activities in FPSC Order No. PSC-02-1396-PAA-EI in

Docket No. 020943-EI . The projected expenses for the 2008 recovery period total $3,061,705.

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

A. The first activity, General Water Quality (Line Item 1.6), identified in Schedule 2P, includes Soil Contamination Studies, Dechlorination, Groundwater Monitoring Plan Revisions, Surface Water Studies, and the Cooling Water Intake Program. This activity was previously approved for ECRC recovery and is projected to incur incremental expenses totaling $338,913 during 2008.

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 line item includes expenses related to substation investigation and remediation activities. Expenses expected to be incurred during the projection period for this line item total $1,396,476.

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 the lead and copper drinking water quality standards. These expenses are expected to total $21,500 during the

2008 projection period.

Q. What activities are included in the environmental affairs administration Category?

A. Only one O&M activity is included in this category on Schedule 2P (Line Item 1.10) of Ms. Martin's exhibit. This line item refers to the Company's Environmental Audit/Assessment function. This program is an on-going compliance activity previously approved for ECRC recovery. Expenses totaling $1,300 are expected during the 2008 recovery period.

Q. What O&M activities are included in the general solid and hazardous waste category?

A. Only one program, General Solid and Hazardous Waste (Line Item 1.11) is included in the solid and hazardous waste category on Schedule 2P. This activity involves the proper identification, handling, storage, transportation and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for Gulf's generating and power delivery facilities. This program is a previously approved program that is projected to incur incremental expenses totaling $331,185 in 2008.

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

A. Yes. There are four other O&M activities that have been approved in past

proceedings which have projected expenses. They are the Above Ground Storage Tanks program, the Sodium Injection System, the CAIR/CAMR/CAVR Compliance Program, and SO_2 Allowances.

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

A. Above Ground Storage Tanks (Line Item 1.12) includes integrity testing and maintenance activities required by Florida's above ground storage tank regulation, Chapter 62 Part 762, F.A.C. Expenses totaling $180,500 are projected to be incurred during 2008.

Q. What activity is included in the Sodium Injection line item?

A. The Sodium Injection System (Line Item 1.16) was originally approved for inclusion in the ECRC in Order No. PSC-99-1954-PAA-EI. The activities in this line item involve sodium injection to the coal supply that enhances precipitator efficiencies when burning certain low sulfur coals at the plants. The expenses projected for the 2008 recovery period total $238,000.

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

A. The CAIR/CAMR/CAVR Compliance Program (Line Item 1.20) is being included in the ECRC projection for the first time. This line item currently includes O&M expenses associated with the mercury monitoring projects that were included as part of the CAIR/CAMR/CAVR Compliance Program stipulation approved by the Commission on August 14, 2007. The

projected expenses for the 2008 recovery period total $275,401.

Q. Please describe the emission allowances line items 1.21 through 1.24.

A. These line items include projected allowance expenses for Gulf's generating plants. There are currently no projected allowance expenses for line items 1.21 through 1.23 during 2008. Line Item 1.24 represents projected expenses for SO_2 allowances expected to be utilized during 2008. The SO_2 expenses are offset by the amortization of gains from the sale of SO_2 allowances.

Q. Do each of the capital projects and O&M activities that have projected costs in 2008 meet the ECRC statutory guidelines?

A. Yes, the projects included in Gulf's 2008 ECRC projection filing meet the requirements of the ECRC statute and are consistent with the Commission's precedent regarding environmental cost recovery. Each of the capital projects and O&M activities set forth on Ms. Martin's schedules include only prudent costs incurred after April 13, 1993 that are not recovered through some other cost recovery mechanism or base rates. The projected environmental costs are necessary to achieve and/or maintain compliance with environmental laws, rules, and regulations.

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

A. Yes.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Rhonda J. Martin
Docket No. 070007-EI
Date of Filing: April 2, 2007

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

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

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

A. I graduated from the University of West Florida in Pensacola, Florida in 1994 with a Bachelor of Arts Degree in Accounting. I am also a licensed Certified Public Accountant and a member of the Florida Institute of Certified Public Accountants. I joined Gulf Power in 1994 as an Accountant. Prior to assuming my current position, I have held various positions of increasing responsibility with Gulf as an accountant in the Accounting Services, Financial Reporting, and Corporate Accounting Departments and as Supervisor of Financial Planning. In April 2006, I joined the Rates and Regulatory Matters area.

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

Q. Are you the same Rhonda J. Martin who has previously testified before this Commission in this on-going docket?

A. Yes.

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

A. Yes, I have.

Counsel: We ask that Ms. Martin's Exhibit consisting of eight schedules be marked as Exhibit No. _____(RJM-1).

Q. Are you familiar with the Environmental Cost Recovery Clause (ECRC) True-up Calculation for the period of January through December 2006 set forth in your exhibit?

A. Yes. These documents were prepared under my supervision.

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

A. Yes.

Q. What is the amount to be refunded or collected in the recovery period beginning January 2008?

A. An amount to be refunded of $2,258,385 was calculated, which is reflected on line 3 of Schedule 1A of my exhibit.

Q. How was this amount calculated?

A. The $2,258,385 to be refunded was calculated by taking the difference between the estimated January 2006 through December 2006 over-recovery of $2,874,720 as approved in FPSC Order No. PSC-06-0972-FOF-EI, dated November 22, 2006, and the actual over-recovery of $5,133,105, which is the sum of lines 5, 6, and 10 on Schedule 2A of my exhibit.

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

A. Schedule 2A shows the calculation of the actual over-recovery of environmental costs for the period January 2006 through December 2006. 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 2006 through December 2006 with the estimated/actual O&M expenses included in the approved estimated true-up filed in conjunction with the November 2006 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 final true-up testimony.

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

A. Schedule 6A for the period January 2006 through December 2006 compares the actual recoverable costs related to investment with the estimated/actual amount included in the approved estimated true-up filed in conjunction with the November 2006 hearing. The recoverable costs include the return on investment, depreciation and amortization expense, dismantlement accrual, and property taxes associated with each environmental capital project for the recovery period. Recoverable costs also include a return on working capital associated with emission allowances. Schedule 7A provides the monthly recoverable costs associated with each project, along with the calculation of the jurisdictional recoverable costs. Mr. Vick describes any major variances in recoverable costs related to environmental investment for this period in his final true-up testimony.

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 and amortization expense, dismantlement accrual, property taxes, and the cost of emission allowances. Pages 1 through 25 of Schedule 8A show the investment and associated costs related to capital projects, while page 26 shows the investment and costs related to emission allowances.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Rhonda J. Martin
Docket No. 070007-EI
Date of Filing: August 3, 2007

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

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

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

A. I graduated from the University of West Florida in Pensacola, Florida in 1994 with a Bachelor of Arts Degree in Accounting. I am also a licensed Certified Public Accountant and a member of the Florida Institute of Certified Public Accountants. I joined Gulf Power in 1994 as an Accountant. Prior to assuming my current position, I have held various positions of increasing responsibility with Gulf as an accountant in the Accounting Services, Financial Reporting, and Corporate Accounting Departments and as Supervisor of Financial Planning. In April 2006, I joined the Rates and Regulatory Matters area.

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

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

A. Yes, I have.

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

A. Yes, I have. My exhibit consists of 8 schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Ms. Martin's Exhibit consisting of 8 schedules be marked as Exhibit No. _____(RJM-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 2007 through December 2007 period to be refunded or collected in the period January 2008 through December 2008?

A. The estimated true-up for the current period is an under-recovery of $2,117,926 as shown on Schedule 1E. This is based on six months of actual data and six months of estimated data. This amount will be netted against the 2006 final true-up over-recovery amount of $2,258,385 (see Schedule 1A to my testimony filed April 2, 2007). The sum of $140,459 will be refunded to customers during the January 2008

through December 2008 period. The detailed calculations supporting the estimated true-up for 2007 are contained in Schedules 2E through 8E.

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

A. Schedule 2E shows the calculation of the estimated under-recovery of environmental costs for the period January 2007 through December 2007. Schedule 3E of my exhibit is the calculation of the interest provision on the average true-up balance. This is the same method of calculating interest that is used in the Fuel Cost Recovery and Purchased Power Capacity Cost Recovery clauses.

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

A. Schedule 4E compares the estimated/actual O & M expenses for the period January 2007 through December 2007 with the projected O & M expenses approved by the Commission in conjunction with the November 2006 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 2007 through December 2007 compares the estimated/actual recoverable costs related to investment with the projected amount approved in conjunction with the November 2006 hearing. The recoverable costs include the return on investment, depreciation and amortization expense, dismantlement accrual, and property taxes associated with each environmental capital project for the current recovery period. Recoverable costs also include a return on working capital associated with emission allowances. Schedule 7E provides the monthly recoverable revenue requirements associated with each project, along with the calculation of the jurisdictional recoverable revenue requirements. Mr. Vick describes the major variances in recoverable costs related to environmental investment for this estimated true-up period in his testimony.

Q. Please describe Schedule 8E of your exhibit.

A. Schedule 8E includes 28 pages that provide the monthly calculations of recoverable costs associated with each approved capital project for the current recovery period. As I stated earlier, these costs include return on investment, depreciation and amortization expense, dismantlement accrual, property taxes, and the return on working capital associated with emission allowances. Pages 1 through 27 of Schedule 8E show the investment and associated costs related to capital projects, while page 28 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 based on the capital structure approved in Docket No. 010949-EI, FPSC Order No. PSC-02-0787-FOF-EI dated June 10, 2002. The rate of return used to calculate ECRC revenue requirements includes a return on equity of 12.0% for the period January 1, 2007 through December 31, 2007.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
Rhonda J. Martin
Docket No. 070007-EI
Date of Filing: August 31, 2007

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

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

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

A. I graduated from the University of West Florida in Pensacola, Florida in 1994 with a Bachelor of Arts Degree in Accounting. I am also a licensed Certified Public Accountant and a member of the Florida Institute of Certified Public Accountants. I joined Gulf Power in 1994 as an Accountant. Prior to assuming my current position, I have held various positions of increasing responsibility with Gulf as an accountant in the Accounting Services, Financial Reporting, and Corporate Accounting Departments and as Supervisor of Financial Planning. In April 2006, I joined the Rates and Regulatory Matters area.

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

Q. 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 2008 through December 2008.

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. Martin's exhibit consisting of 7 schedules be marked as Exhibit No. _____ (RJM-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 Order No. PSC-94-0044-FOF-EI in Docket No. 930613-EI and with past proceedings in this ongoing recovery docket. The costs we have identified for recovery through the ECRC are not currently being recovered through base rates or any other cost recovery mechanism.

Q. How was the amount of projected O&M expenses to be recovered through the ECRC calculated?

A. Mr. Vick has provided me with projected recoverable O&M expenses for January 2008 through December 2008. Schedule 2P of my exhibit shows the calculation of the recoverable O&M expenses broken down between 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 (CAAA) were considered to be energy-related, consistent with Commission Order No. PSC-94-0044-FOF-EI. O&M expenses associated with Gulf's Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Clean Air Visibility Rule (CAVR) Compliance Program were considered to be energy-related pursuant to FPSC Order No. PSC-06-0972-FOF-EI issued November 22, 2006. The remaining expenses were broken down between demand and energy consistent with Gulf's last approved cost-of-service methodology in Docket No. 010949-EI.

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

A. Schedule 3P summarizes the monthly recoverable revenue requirements associated with each capital investment project for the recovery period. Schedule 4P shows the detailed calculation of the revenue requirements associated with each investment project. These schedules also include the calculation of the jurisdictional amount of recoverable revenue requirements. Mr. Vick has provided me with the expenditures,

clearings, retirements, salvage, and cost of removal related to each capital project and the monthly costs for emission allowances. From that information, I calculated plant-in-service and construction work in progress (non interest bearing). Depreciation, amortization and dismantlement expense and the associated accumulated depreciation balances were calculated based on Gulf's approved depreciation rates, amortization periods, and dismantlement accruals. The capital projects identified for recovery through the ECRC are those environmental projects which were not included in the approved June 2002 through May 2003 test year on which present base rates were set.

Q. How was the amount of property taxes to be recovered through the ECRC derived?

A. Property taxes were calculated by applying the applicable tax rate to taxable investment. In Florida, pollution control facilities are taxed based only on their salvage value. For the recoverable environmental investment located in Florida, the amount of property taxes is estimated to be $0. In Mississippi, there is no such reduction in property taxes for pollution control facilities. Therefore, property taxes related to recoverable environmental investment at Plant Daniel are calculated by applying the applicable millage rate to the assessed value of the property.

Q. What capital structure and return on equity were used to develop the rate of return used to calculate the revenue requirements?

A. The rate of return used is based on Gulf's capital structure 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 costs associated with compliance with the CAAA were considered to be energy-related consistent with Commission Order No. PSC-94-0044-FOF-EI, dated January 12, 1994, in Docket No. 930613-EI. The investment costs associated with Gulf's CAIR, CAMR, and CAVR Compliance Program were considered to be energy-related pursuant to FPSC Order No. PSC-06-0972-FOF-EI issued November 22, 2006. The remaining investment costs of environmental compliance were allocated 12/13th based on demand and 1/13th based on energy, consistent with Gulf's last 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 2008 through December 2008?

A. The total projected jurisdictional recoverable costs for the period January 2008 through December 2008 is $49,861,194 as shown on line 1c of Schedule 1P. This includes costs related to O&M activities of

$13,659,600 and costs related to capital projects of $36,201,594 as shown on lines 1a and 1b of Schedule 1P.

Q. What is the total recoverable revenue requirement to be recovered in the projection period January 2008 through December 2008 and how was it allocated to each rate class?

A. The total recoverable revenue requirement including revenue taxes is $49,756,534 for the period January 2008 through December 2008 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 $140,459 to be refunded. Schedule 1P also summarizes the energy and demand components of the requested revenue requirement. I allocated these amounts by rate class using the appropriate energy and demand allocators as shown on Schedules 6P and 7P.

Q. How were the allocation factors calculated for use in the Environmental Cost Recovery Clause?

A. The demand allocation factors used in the ECRC were calculated using the 2006 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 $44,344,037 for the period January 2008 through December 2008 was allocated using the energy allocator, as shown in column 3 on Schedule 7P. The demand-related recoverable revenue requirement of $5,412,497 for the period January 2008 through December 2008 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 $4.36 monthly for the period January 2008 through December 2008.

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

A. The factors will be effective beginning with Cycle 1 billings in January 2008 and will continue through the last billing cycle of December 2008.

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

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 070007-EI
FILED: 04/02/07

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

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

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

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

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

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

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

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

A. The purpose of my testimony is to present, for Commission review and approval, the actual true-up amount for the ECRC and the calculations associated with the environmental compliance activities for the January 2006 through December 2006 period.

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

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

January 2006 through December 2006 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 24, consists of the calculation of depreciation expenses and return on capital investment for each project that is being recovered through the ECRC, and page 25 calculates the net expenses associated with maintaining an SO_2 allowance inventory.

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

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and

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

Q. What is the actual true-up amount Tampa Electric is requesting for the January 2006 through December 2006 period?

A. Tampa Electric has calculated and is requesting approval of an over-recovery of $46,451,725 as the actual true-up amount for the January 2006 through December 2006 period.

Q. What is the adjusted net true-up amount Tampa Electric is requesting for the January 2006 through December 2006 period which is to be applied in the calculation of the environmental cost recovery factors to be refunded/(recovered) in the 2008 projection period?

A. Tampa Electric has calculated and is requesting approval of an under-recovery of $11,895,683 reflected on Form 42-1A, as the adjusted net true-up amount for the January 2006 through December 2006 period. This adjusted net true-up amount is the difference between the actual over-recovery and the actual/estimated over-recovery for the

January 2006 through December 2006 period as depicted on Form 42-1A. The actual true-up amount for the January 2006 through December 2006 period is an over-recovery of $46,451,725 as compared to the $58,347,408 actual/estimated over-recovery amount approved in FPSC Order No. PSC-06-0972-FOF-EI issued November 22, 2006.

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

A. All costs listed in Forms 42-4A through 42-8A for which Tampa Electric is seeking recovery are attributable to environmental compliance projects approved by the Commission. However, Form 42-8A, pages 20 - 23, provides expenditures associated with Big Bend Units 1-4 Selective Catalytic Reduction ("SCR") projects and are only included at this time for identification and tracking purposes. Recovery of these expenditures is not included in the 2006 ECRC True-Up. Consistent with the Commission's decisions in Docket Nos. 980693-EI, 040007-EI, 040750-EI and 041376-EI, the company will not seek recovery of the SCR project costs associated with these Commission approved environmental compliance projects until each project is placed in-service. Big Bend Unit 4

SCR was approved in Docket No. 040750-EI, Order No. PSC-04-0986-PAA-EI and is projected to be in-service June 2007. Big Bend Units 1-3 SCRs were approved in Docket No. 041376-EI, Order No. PSC-05-0502-PAA-EI and are projected to be in-service May 2008, May 2009 and May 2010, respectively.

Q. Please explain the adjustment of $41,743 contained on Form 42-2A, line 10.

A. The adjustment of $41,743, including interest, represents an inadvertent error that occurred when calculating the actual O&M expense for the Big Bend Units 1 and 2 Flue Gas Desulfurization project. The error was discovered and corrected during the 2006 Commission audit of Tampa Electric's 2005 ECRC True-Up. With this adjustment, Tampa Electric customers have been made whole.

Q. Is Tampa Electric including costs in this ECRC true-up filing for any environmental projects that were not anticipated and included in its 2006 factors?

A. Yes. On September 29, 2005, Tampa Electric filed a petition for approval of cost recovery of the Arsenic Groundwater Standard Program that is required by the

Environmental Protection Agency and the Florida Department of Environmental Protection. Effective January 1, 2005, regulated entities of the State of Florida are required to monitor the drinking water and groundwater maximum contaminant level for arsenic under the federal rule known as the Safe Drinking Water Act.

In Docket No. 050683-EI, Order No. PSC-06-0138-PAA-EI, issued February 23, 2006, the Commission granted Tampa Electric cost recovery approval for prudent costs associated with this project. The new standard applies to Tampa Electric's H.L. Culbreath Bayside, Big Bend and Polk Power Stations.

Additionally, Tampa Electric filed a petition on December 27, 2005, for approval of cost recovery for the Big Bend Flue Gas Desulfurization ("FGD") System Reliability program. This program is necessary for reliable FGD system operations after the 2010 and 2013 deadlines mandated by the Consent Decree.

In Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2006, the Commission granted cost recovery approval for prudent costs associated with this program. The Big Bend FGD System Reliability program

will run concurrently with the installation of SCR systems on the generating units.

On the July 21, 2006, the Office of Public Counsel ("OPC") filed a protest to the aforementioned Commission order. The company has proceeded with the inclusion of the prudently incurred program costs pending the outcome of the March 2007 hearing.

The 2006 costs associated with both of these programs are included in this ECRC true-up filing.

Q. How did actual expenditures for the January 2006 through December 2006 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 $13,314,949 or 29.1 percent greater than actual/estimated projections. Form 42-6A shows the total capital investment costs were $12,664 or 0.1 percent lower than actual/estimated projections. O&M and capital investment projects with material variances from the 2006 Actual/Estimated True-Up filing are explained below.

O&M Project Variances

- **Big Bend Unit 3 Flue Gas Desulfurization Integration:** The Big Bend Unit 3 Flue Gas Desulfurization Integration project variance was $309,808 or 7.5 percent greater than projected due to increased maintenance of the limestone handling equipment. Additionally, repairs on structural steel, absorber recycle pumps, the oxidation air compressor and the quencher were necessary.
- **SO_2 Emissions Allowances:** The SO_2 Emission Allowances project variance was $13,128,217 or 22.7 percent greater than projected. The variance was due to lower market prices for allowances that resulted in fewer allowances being sold than originally projected.
- **Big Bend PM Minimization and Monitoring:** The Big Bend PM Minimization and Monitoring project variance was $108,979 or 33.5 percent lower than projected due to decreased outage inspection work stemming from improved precipitator performance.
- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance was $46,701 or 5.5 percent lower than projected due to lower than forecasted costs for scaffolding used during the boiler tube inspection of Big Bend Unit 1.
- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance was $22,745 or 26.7

percent higher than projected. The variance was due to unusually wet conditions in 2005, which limited dry season sampling. For that reason, dry sampling was completed in 2006.

- **Polk NO_x Emissions Reduction:** The Polk NO_x Emissions Reduction project variance was $4,096 or 10.2 percent greater than originally projected due to increased maintenance performed on the saturator than originally anticipated.
- **Bayside SCR Consumables:** The Bayside SCR Consumables project variance was $3,445 or 5.3 percent greater than projected due to increased ammonia costs and added fuel surcharges for delivery.
- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study was $142,415 or 21.0 percent less than projected due to the slower rate of sampling for the impingement survival study. The sampling activity is expected to resume the normal schedule in 2007.
- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard program variance was $5,811 or 103.9 percent greater than projected due to an unplanned request by the Florida Department of Environmental Protection for a soil characterization analysis performed at the Bayside Power Station.

Capital Investment Project Variances

- **Big Bend FGD System Reliability:** The Big Bend FGD System Reliability program variance was $5,197 or 13.2 percent less than projected due to the decrease in material costs for the Split Inlet/Outlet Duct project as well as the delay of the Controls Redundancy project. The spending for the Controls Redundancy project commenced in 2007.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 070007-EI
FILED: 08/03/07

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 2007 through December 2007 estimated true-up amount to be refunded or recovered through the ECRC during January 2008 through December 2008. My testimony addresses the recovery of capital and operating and maintenance ("O&M") costs associated with environmental compliance activities for 2007, based on six months of actual data and six months of estimated data. This information will be used to determine the environmental cost recovery factors for January 2008 through December 2008.

Q. Have you prepared an exhibit that shows the determination of the recoverable environmental costs for the period January 2007 through December 2007?

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 estimated true-up amount to be used in calculating the cost recovery factors for January 2008 through December 2008.

Q. What has Tampa Electric calculated as the estimated true-up for the current period to be applied to the January 2008 through December 2008 ECRC factors?

A. The estimated true-up applicable for the current period, January 2007 through December 2007, is an over-recovery of $9,624,173. A detailed calculation supporting the estimated true-up is shown on Forms 42-1E through 42-8E of my exhibit.

Q. Is Tampa Electric including costs in this estimated true-up filing for any environmental projects that were not anticipated and included in its 2007 factors?

A. No.

Q. What depreciation rates were utilized for the capital projects contained in the 2007 Actual/Estimated True-Up?

A. Tampa Electric utilized the depreciation rates approved by the Commission in Docket No. 070284-EI on July 31, 2007.

Q. How did the actual/estimated project expenditures for January 2007 through December 2007 period compare with the company's original projection?

A. As shown on Form 42-4E, total O&M activities were $7,244,683 less than projected costs. Total capital expenditures itemized on Form 42-6E, were $2,122,627 lower than originally projected. O&M and capital investment projects with material variances are explained below.

O&M Project Variances

- **Big Bend Unit 3 Flue Gas Desulfurization Integration:** The Big Bend Unit 3 Flue Gas Desulfurization Integration project variance is estimated to be $500,751 or 12.5 percent greater than originally projected due to the

increase in common maintenance on Units 3 and 4 due to the Unit 4 outage.

- **SO_2 Emission Allowances**: The SO_2 Emission Allowances project variance is estimated to be $5,560,610 or 7.5 percent less than projected. The variance was due to a greater amount of allowances sold than originally projected passing the revenue onto customers to offset otherwise projected expenses.
- **Big Bend Units 1 and 2 Flue Gas Desulfurization**: The Big Bend Unit 1 and 2 Flue Gas Desulfurization project variance is estimated to be $1,144,209 or 17.3 percent less than originally projected due to the ability to coordinate maintenance activities with scheduled outages.
- **Big Bend PM Minimization and Monitoring**: The Big Bend PM Minimization and Monitoring project variance is estimated to be $140,000 or 31.1 percent less than originally projected due to the decreased inspection work during the Unit 4 outage and overall improved precipitator performance.
- **Big Bend NO_x Emissions Reduction**: The Big Bend NO_x Emissions Reduction project variance is estimated to be $140,000 or 40.0 percent greater than originally projected due to unanticipated inspections for boiler tube degradation stemming from NO_x abatement measures as well as burner modifications.

- **Gannon Thermal Discharge Study:** The Gannon Thermal Discharge Study project variance is estimated to be $16,117 or 161.2 percent higher than originally projected. The variance was due to unusually wet conditions in 2005, which limited dry season sampling. For that reason, dry sampling was completed in late 2006 and the invoicing carried over into 2007.
- **Big Bend Unit 4 SOFA:** The Big Bend Unit 4 SOFA project variance is estimated to be $30,000 or 12.0 percent lower than originally projected due to less maintenance activity than anticipated.
- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance is estimated to be $75,000 or 100 percent less than originally projected due to the delay of the in-service date for the capital project.
- **Big Bend Unit 2 Pre-SCR:** The Big Bend Unit 2 Pre-SCR project variance is estimated to be $60,000 or 80 percent less than originally projected due to the delay of the in-service date for the capital project.
- **Clean Water Act Section 316(b) Phase II Study:** The Clean Water Act Section 316(b) Phase II Study project variance is estimated to be $339,434 or 46.1 percent less than projected. The variance is due to the sampling of the impingement survival study occurring at a slower rate than originally projected. The sampling activity is

anticipated to resume the normal schedule in late 2007.

- **Arsenic Groundwater Standard Program:** The Arsenic Groundwater Standard Program variance is estimated to be $5200 or 50.0 percent less than projected. The project is on hold pending comments from the Florida Department of Environmental Protection ("FDEP").
- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is estimated to be $496,127 or 39.5 percent less than originally projected due to less flyash mitigation costs compared to the original projection as well as the decreased projection for the usage of less ammonia. The unit went into commercial operation in May.

Capital Investment Project Variances

- **Big Bend Unit 1 Pre-SCR:** The Big Bend Unit 1 Pre-SCR project variance is estimated to be $48,883 or 14.7 percent less than the original projection due to the delay of the project as the Unit 4 SCR performance is verified.
- **Big Bend Unit 3 Pre-SCR:** The Big Bend Unit 3 Pre-SCR project variance is estimated to be $28,386 or 17.5 percent less than the original projection due to the deferment of activities and associated costs to 2008 after the completion of the outage that is scheduled for the end of 2007.

- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is estimated to be $485,450 or 8.6 percent less than originally projected due to the decrease in materials, hardware and software costs as part of the combustion neural network as well as the costs for construction labor being below the originally forecasted value. The unit went into commercial operation in May.
- **Big Bend FGD Reliability:** The Big Bend FGD Reliability project variance is estimated to be $127,300 or 14.0 percent less than projected due to project materials originally scheduled for delivery in 2007 that were actually received in late 2006.
- **Clean Air Mercury Rule:** The Clean Air Mercury Rule project is on hold pending comments from FDEP before the study can resume.
- **SO_2 Emission Allowances:** The SO_2 Emission Allowances project variance is estimated to be $61,420 or 1107.1 percent less than originally projected. The variance is due to the sale of more allowances than originally projected.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 070007-EI
FILED: 8/31/2007

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HOWARD T. BRYANT

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

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

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

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

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

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

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

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

A. The purpose of my testimony is to present, for Commission review and approval, both the calculation of the revenue requirements and the projected ECRC factors for the period of January 2008 through December 2008. 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 2008.

Q. Have you prepared an exhibit that shows the determination of recoverable environmental costs for the period of January 2008 through December 2008?

A. Yes. Exhibit No. ___ (HTB-3), containing one document, was prepared under my direction and supervision. It includes Forms 42-1P through 42-7P, which show the calculation and summary of O&M, and capital expenditures that support the development of the environmental cost recovery factors for 2008.

Q. What has Tampa Electric calculated as the net true-up to be applied in the period January 2008 through December 2008?

A. The net true-up applicable for this period is an under-recovery of $2,271,510. This consists of the final true-up under-recovery of $11,895,683 for the period of January 2006 through December 2006 and an estimated true-up over-recovery of $9,624,173 for the current period of January 2007 through December 2007. The detailed calculation supporting the estimated net true-up was provided on Forms 42-1E through 42-8E of Exhibit No. ___ (HTB-2) filed with the Commission on August 3, 2007.

Q. What is the major contributing factor that has created the net under-recovery to be applied to the company's ECRC rates for the period January 2008 through December 2008?

A. The major contributing factor that has created the net under-recovery was the anticipated sale of surplus SO_2 emission allowances that was projected to occur in 2006 but instead occurred during 2007.

Q. Does Tampa Electric anticipate the sale of surplus SO_2 allowances during 2008?

A. Yes. The company anticipates the sale of approximately $30 million of surplus SO_2 allowances during 2008. The revenues from the allowance sales have an immediate, direct benefit to Tampa Electric customers since they offset environmental expenses. Additional details associated with the 2008 sales are provided by Tampa Electric Witness, Paul L. Carpinone.

Q. Has Tampa Electric proposed any new environmental compliance projects for ECRC cost recovery for the period from January 2008 through December 2008?

A. No.

Q. What are the existing capital projects included in the calculation of the ECRC factors for 2008?

A. Tampa Electric proposes to include for ECRC recovery the 24 previously approved capital projects and their projected costs in the calculation of the ECRC factors for 2008. These projects are:

1) Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration
2) Big Bend Units 1 and 2 Flue Gas Conditioning
3) Big Bend Unit 4 Continuous Emissions Monitors
4) Big Bend Unit 1 Classifier Replacement
5) Big Bend Unit 2 Classifier Replacement
6) Big Bend Section 114 Mercury Testing Platform
7) Big Bend Units 1 and 2 FGD
8) Big Bend FGD Optimization and Utilization
9) Big Bend NO_x Emissions Reduction
10) Big Bend Particulate Matter ("PM") Minimization and Monitoring
11) Polk NO_x Emissions Reduction
12) Big Bend Unit 4 SOFA
13) Big Bend Fuel Oil Tank No. 1 Upgrade
14) Big Bend Fuel Oil Tank No. 2 Upgrade
15) Phillips Tank No. 1 Upgrade
16) Phillips Tank No. 4 Upgrade
17) Big Bend Unit 1 Pre-SCR
18) Big Bend Unit 2 Pre-SCR

19) Big Bend Unit 3 Pre-SCR
20) Big Bend Unit 3 SCR
21) Big Bend Unit 4 SCR
22) Big Bend FGD Reliability
23) Clean Air Mercury Rule
24) SO_2 Emission Allowances

Some of these projects will be described in more detail by Tampa Electric Witness, Paul L. Carpinone.

Q. Have you prepared schedules showing the calculation of the recoverable capital project costs for 2008?

A. Yes. Form 42-3P contained in Exhibit No. ___ (HTB-3) summarizes the cost estimates projected for these projects. Form 42-4P, pages 1 through 26, provides the calculations of the costs, which result in recoverable jurisdictional capital costs of $32,324,120.

Q. What are the existing O&M projects included in the calculation of the ECRC factors for 2008?

A. Tampa Electric proposes to include for ECRC recovery the 18 previously approved O&M projects and their projected costs in the calculation of the ECRC factors for 2008.

These projects are:

1) Big Bend Unit 3 FGD Integration
2) Big Bend Units 1 and 2 Flue Gas Conditioning
3) SO_2 Emissions Allowances
4) Big Bend Units 1 and 2 FGD
5) Big Bend PM Minimization and Monitoring
6) Big Bend NO_x Emissions Reduction
7) Polk NO_x Emissions Reduction
8) Bayside SCR and Ammonia
9) Big Bend Unit 4 SOFA
10) Big Bend Unit 1 Pre-SCR
11) Big Bend Unit 2 Pre-SCR
12) Big Bend Unit 3 Pre-SCR
13) Big Bend Unit 4 SCR
14) NPDES Annual Surveillance Fees
15) Gannon Thermal Discharge Study
16) Clean Water Act Section 316(b) Phase II Study
17) Arsenic Groundwater Standard Program
18) Big Bend Unit 3 SCR

Some of these projects will be described in more detail by Tampa Electric Witness, Paul L. Carpinone.

Q. Have you prepared schedules showing the calculation of

the recoverable O&M project costs for 2008?

A. Yes. Form 42-2P contained in Exhibit No. ___ (HTB-3) summarizes the recoverable jurisdictional O&M costs for these projects which total ($13,412,877) for 2008.

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

A. Yes. Project descriptions and progress reports, as well as the projected recoverable cost estimates, are provided in Form 42-5P, pages 1 through 31.

Q. What are the total projected jurisdictional costs for environmental compliance in the year 2008?

A. The total jurisdictional O&M and capital expenditures to be recovered through the ECRC are calculated on Form 42-1P. These expenditures total $18,911,243.

Q. How were environmental cost recovery factors calculated?

A. The environmental cost recovery factors were calculated as shown on Schedules 42-6P and 42-7P. The demand

allocation factors were calculated by determining the percentage each rate class contributes to the monthly system peaks and then adjusted for losses for each rate class. The energy allocation factors were determined by calculating the percentage that each rate class contributes to total kWh sales and then adjusted for losses for each rate class. This information was obtained from Tampa Electric's 2004 load research study. Form 42-7P presents the calculation of the proposed ECRC factors by rate class.

Q. What are the 2008 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 2008 proposed ECRC billing factors are as follows:

Rate Class	**Factor (¢/kWh)**
Average Factor	0.104
RS, RST	0.104
GS, GST, TS	0.104
GSD, GSDT	0.105
GSLD, GSLDT, SBF	0.104
IS1, IST1, SBI1, IS3, IST3, SBI3	0.102

SL, OL 0.105

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

A. The environmental cost recovery credits will be effective concurrent with the first billing cycle for January 2008.

Q. Are the costs Tampa Electric is requesting for recovery through the ECRC for the period January 2008 through December 2008 consistent with criteria established for ECRC recovery in Order No. PSC-94-0044-FOF-EI?

A. Yes. The costs for which ECRC treatment is requested meet the following criteria:

1. Such costs were prudently incurred after April 13, 1993;
2. The activities are legally required to comply with a governmentally imposed environmental regulation enacted, became effective or whose effect was triggered after the company's last test year upon which rates are based; and
3. Such costs are not recovered through some other cost recovery mechanism or through base rates.

Q. Please summarize your testimony.

A. My testimony supports the approval of a final average environmental billing factor credit of 0.104 cents per kWh which includes projected capital and O&M revenue requirements of $18,911,243 associated with a total of 31 environmental projects and a true-up under-recovery provision of $2,271,510 primarily driven by SO_2 allowance sales. My testimony also explains that the projected environmental expenditures for 2008 are appropriate for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 070007-EI
FILED: 8/31/2007

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PAUL L. CARPINONE

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

A. My name is Paul Carpinone. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Environmental, Health and Safety.

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

A. I received a Bachelor of Science degree in Water Resources Engineering Technology from the Pennsylvania State University in 1978. I have been a Registered Professional Engineer in the State of Florida since 1984. Prior to joining Tampa Electric, I worked for Seminole Electric Cooperative as a Civil Engineer in various positions and in environmental consulting. In February 1988, I joined Tampa Electric as a Principal Engineer, and I have primarily worked in the area of Environmental Health & Safety. In 2006, I became Director of

Environmental Health and Safety. My responsibilities include the development and administration of the company's environmental, health and safety policies and goals. Additionally, I am also responsible for ensuring resources, procedures and programs meet or exceed compliance with applicable environmental, health and safety requirements, and that rules and policies are in place and functioning appropriately and consistently throughout the company.

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

A. The purpose of my testimony is to demonstrate that the activities for which Tampa Electric seeks cost recovery through the ECRC for the January 2008 through December 2008 projection period are activities necessary for the company to comply with various environmental requirements. Specifically, I will describe the ongoing activities that are associated with the Consent Final Judgment ("CFJ") entered into with the Florida Department of Environmental Protection ("FDEP") and the Consent Decree ("CD") lodged with the U.S. Environmental Protection Agency ("EPA") and the Department of Justice. I will also discuss other programs previously approved by the Commission for recovery through the ECRC as well as

the suspension of the Clean Water Act Section 316(b) Phase II Study. Finally, I will discuss the sulfur dioxide ("SO_2") emission allowance sales for 2008 and the company's position for future allowance needs.

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

The general ongoing requirements of the Orders provide for further reductions for SO_2, particulate matter ("PM") and nitrous oxides ("NO_x") emissions at Big Bend Station.

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

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

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

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

Phase II outlined capital projects that Tampa Electric was to perform to upgrade each scrubber at Big Bend Station. It also addressed the use of environmental dispatching in the event of a scrubber outage. All of the preliminary SO_2 emissions reduction projects have been completed. However, additional work will occur in 2008 associated with the Big Bend Units 1 and 2 FGD and Big Bend FGD System Reliability programs to comply with the elimination of the allowed scrubber outage days for 2010 and 2013.

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

A. The Orders require Tampa Electric to develop and implement a best operational practices ("BOP") study to minimize PM emissions from each electrostatic precipitator ("ESP") and complete and implement a best available control technology ("BACT") analysis of the ESPs at Big Bend Station. The Orders also require the company to demonstrate the operation of a PM continuous emissions monitoring system ("CEM") on Big Bend Units 3

and 4 and demonstrate the operation of a second PM CEM on another Big Bend unit. Pursuant to the Orders, the installation of the second PM CEM is required on or before May 1, 2007, if the first PM CEM has been shown to be feasible and remains in operation and if Tampa Electric advises the EPA that it has elected to continue to combust coal in Big Bend Units 1, 2 and 3. The first PM CEM was installed in February 2002. The installation of the second PM CEM will commence within 18 months of approval of the pending second amendment to the CD. The delay is due to disputes between the company and EPA over the feasibility of the first unit.

Q. Please describe the Big Bend PM Minimization and Monitoring program activities and provide the estimated capital and O&M expenditures for the period of January 2008 through December 2008.

A. The Big Bend PM Minimization and Monitoring program was approved by the Commission in Docket No. 001186-EI, Order No. PSC-00-2104-PAA-EI, issued November 6, 2000. In the Order, the Commission found that the program met the requirements for recovery through the ECRC. Tampa Electric had previously identified various projects to improve precipitator performance and reduce PM emissions

as required by the Orders. In 2008, there will be capital expenditures associated with the installation of a second PM CEM, O&M expenses associated with existing and recently installed BOP and BACT equipment and continued implementation of the BOP procedures. These activities are expected to result in approximately $500,000 of capital and $450,000 of O&M expenses.

Q. What do the Orders require for NO_x reductions?

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

Q. Please describe the Big Bend NO_x Emissions Reduction program activities and provide the estimated capital and O&M expenses for the period of January 2008 through December 2008.

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. Tampa Electric will perform the requisite capital replacement and maintenance on the previously approved NO_x reduction projects. These activities are expected to result in approximately $375,000 and $350,000 of capital and O&M expenses, respectively and includes the optimization of the combustion neural network for Big Bend Unit 2.

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

A. The Orders require Big Bend Unit 4 to begin operating with a Selective Catalytic Reduction ("SCR") system or other NO_x control technology, be repowered, or 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 one unit per year by May 1, 2008, May 1, 2009 and May 1, 2010, respectively.

In order to meet the NO_x emission rates and timing requirements of the Orders, Tampa Electric engaged an experienced consulting firm, Sargent and Lundy, to assist with the performance of a comprehensive study designed to identify the long-range plans for the generating units at Big Bend Station. The results of the study clearly indicated that the option to remain coal-fired at Big Bend Station and installing the necessary NO_x reduction technologies is the most cost-effective alternative to satisfy the NO_x emissions reductions required by the Orders. This decision was communicated to the EPA and FDEP in August 2004. Tampa Electric also apprised the Commission of this decision in its filing made in Docket No. 040750-EI in August 2004.

Q. Please describe the Big Bend Units 1 through 3 Pre-SCR and the Big Bend Units 1 through 4 SCR projects and provide estimated capital and O&M expenditures for the period of January 2008 through December 2008.

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

Docket No. 041376-EI, Order No. PSC-05-0502-PAA-EI, issued May 9, 2005. The purpose of the Pre-SCR technologies is to reduce inlet NO_x concentrations to the SCR systems, thereby mitigating overall SCR capital and O&M costs. These Pre-SCR technologies include neural networks, windbox modifications, secondary air controls and coal/air flow controls. The SCR projects at Big Bend Units 1 through 4 encompass the design, procurement, installation and annual O&M expenses associated with an SCR system for each unit.

The projected costs for the period of January 2008 through December 2008 for which Tampa Electric is seeking ECRC recovery are for the Big Bend Units 1 through 3 Pre-SCR and Big Bend Units 3 and 4 SCR capital and O&M expenditures associated with the engineering, procurement, construction, start-up, tuning, operation and ongoing maintenance for the projects. No capital expenditures are anticipated for Big Bend Units 1 and 2 Pre-SCR for 2008 however, $75,000 each, is projected for O&M expenses. The projected capital expenditures for Big Bend Unit 3 Pre-SCR are $890,000 with no O&M expenses expected for the year. Big Bend Unit 3 SCR will be placed in-service in April 2008. The capital expenditures for the project are anticipated to be $17,301,000 with O&M expenses of

$1,607,000. Big Bend Unit 4 SCR was placed in-service May 2007 therefore there will not be any capital expenditures for 2008. However, the O&M expenses for this project are anticipated to be $1,610,000.

The projected capital expenditures for Big Bend Units 1 and 2 SCR projects are $15,453,000 and $41,295,000 respectively. However, as stated in Tampa Electric Witness, Howard T. Bryant's Prepared Direct Testimony in this docket, the company will not seek recovery of capital expenditures until the in-service date for each project has occurred.

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

A. The programs previously approved by the Commission include:

1) Big Bend Unit 3 FGD Integration
2) Big Bend Units 1 and 2 FGD
3) Gannon Thermal Discharge Study
4) Bayside SCR Consumables
5) Big Bend Unit 4 Separated Over-fired Air ("SOFA")
6) Clean Water Act Section 316(b) Phase II Study

7) Big Bend FGD Reliability

8) Arsenic Groundwater Standard

9) Clean Air Mercury Rule ("CAMR")

Q. Please describe the Big Bend Unit 3 FGD Integration and the Big Bend Units 1 and 2 FGD activities and provide the estimated capital and O&M expenditures for the period of January 2008 through December 2008.

A. The Big Bend Unit 3 FGD Integration program was approved by the Commission in Docket No. 960688-EI, Order No. PSC-96-1048-FOF-EI, issued August 14, 1996. The Big Bend Units 1 and 2 FGD program was approved by the Commission in Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999. In those Orders, the Commission found that the programs met the requirements for recovery through the ECRC. The programs were implemented to meet the SO_2 emissions requirements of the Phase I and II Clean Air Act Amendments ("CAAA") of 1990.

The projected January 2008 through December 2008, O&M expenses for the Big Bend Unit 3 FGD Integration project are $3,688,900. No capital expenditures are anticipated for this project. The projected January 2008 through December 2008, capital and O&M expenditures for the Big

Bend Units 1 and 2 FGD project are $1,966,000 and $7,243,000, respectively. The major components of the capital expenditures are projected to be for the electric isolation, mist eliminator upgrades and the gypsum filter vacuum pump upgrade. The major component of the expenses is projected to be reagents utilized in the scrubbing process with the balance of expenses being incurred for normal maintenance.

Q. Please describe the Gannon Thermal Discharge Study program activities and provide the estimated capital and O&M expenditures for the period of January 2008 through December 2008.

A. The Gannon Thermal Discharge Study program was approved by the Commission in Docket No. 010593-EI, Order No. PSC-01-1847-PAA-EI, issued September 14, 2001. In that Order, the Commission found that the program met the requirements for recovery through the ECRC. For the period of January 2008 through December 2008, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses will be approximately $50,000 for the period.

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

expenditures for the period of January 2008 through December 2008.

A. The Bayside SCR and Ammonia program was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. For the period of January 2008 through December 2008, there will be no capital expenditures for this program. Tampa Electric anticipates O&M expenses associated with the consumable goods (primarily anhydrous ammonia) will be approximately $70,000 for the period.

Q. Please describe the Big Bend Unit 4 SOFA program activities and provide the capital and O&M expenditures for the period of January 2008 through December 2008.

A. The Big Bend Unit 4 SOFA program was approved by Commission for ECRC recovery in Docket No. 030226-EI, Order No. PSC-03-0684-PAA-EI, issued June 6, 2003. In the Order the Commission found that the program met the requirements for recovery through the ECRC, contingent upon Big Bend Unit 4 remaining coal fired. On August 19, 2004, Tampa Electric submitted a letter to the EPA declaring the intent for Big Bend Units 1 through 4 to remain coal fired and, as such, complied with the

applicable provisions of the CD associated with the decision. The SOFA project was completed in 2004. For the period of January 2008 through December 2008, there will be no capital expenditures for this program. Tampa Electric anticipates annual O&M expenses will be approximately $50,000 for the period.

Q. Please describe the Clean Water Act Section 316(b) Phase II Study program activities and provide the estimated capital and O&M expenditures for the period of January 2008 through December 2008.

A. The Clean Water Act Section 316(b) Phase II Study program was approved by the Commission in Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005. For the period of January 2008 through December 2008, there will be no capital expenditures for this program. EPA announced on March 20, 2007, that the rule adopted pursuant to Section 316(b) be considered suspended. The suspension of the final rule was made on July 9, 2007. Tampa Electric believes that the work will continue to be useful for purposes related to the Phase II Rule and does not intend to suspend the work because it would not be cost-effective or appropriate to do so. Therefore, Tampa Electric anticipates O&M expenses associated with the

sampling activities will be approximately $150,000 for the period.

Q. Please describe the Big Bend FGD System Reliability program activities and provide the estimated capital and O&M expenses for the period of January 2008 through December 2008.

A. Tampa Electric's Big Bend FGD System Reliability program was approved by the Commission in Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2006. The Commission granted cost recovery approval for prudent costs associated with this project. The Big Bend FGD System Reliability project will run concurrently with the installation of SCR systems on the generating units.

For the period of January 2008 through December 2008, Tampa Electric will perform work associated with upgrading the booster fan, electrically isolating the FGD systems, the splitting of the inlet duct as well as other related activities for Big Bend Units 3 and 4. These activities are expected to result in approximately $3,704,000 of capital expenditures. No O&M expenses are anticipated for the period.

Q. Please describe the Arsenic Groundwater Standard program activities and provide the estimated capital and O&M expenditures for the period of January 2008 through December 2008.

A. The Arsenic Groundwater Standard program was approved by the Commission in Docket No. 050683-EI, Order No. PSC-06-0138-PAA-EI, issued February 23, 2006. In that Order, the Commission found that the program met the requirements for recovery through the ECRC and granted Tampa Electric cost recovery approval for prudently incurred costs. The new groundwater standard applies to Tampa Electric's H.L. Culbreath Bayside, Big Bend and Polk Power Stations.

For the period of January 2008 through December 2008, there will be no capital expenditures for this program; however, Tampa Electric anticipates O&M expenses associated with the sampling activities will be approximately $57,000.

Q. Please describe the CAMR program activities and provide the estimated capital and O&M expenditures for the period of January 2008 through December 2008.

A. The CAMR program was approved by the Commission in Docket

No. 060583-EI, Order No. PSC-06-0926-PAA-EI, issued November 6, 2006. In that Order, the Commission found that the program met the requirements for recovery through the ECRC and granted Tampa Electric cost recovery approval for prudently incurred costs. The CAMR program addresses the EPA established standards of performance for mercury emissions for new and existing coal-fired electric utility steam generating units as defined in the federal CAAA Section 111, known as CAMR, effective January 2009. CAMR will permanently cap and reduce mercury emissions nation-wide in two phases: Phase I cap is 38 tons per year with a compliance date of 2010 and Phase II cap is 15 tons per year with a compliance date of 2018. The FDEP administers the CAMR as delineated in Chapter 62-204, 62-210 and 62-296, Florida Administrative Code ("F.A.C.").

Tampa Electric's Big Bend and Polk Power Stations will be affected by the nation-wide mercury emissions reduction rule. The company will install CEMs or sorbent trap monitoring systems that sample mercury found in flue gas.

For the period of January 2008 through December 2008, Tampa Electric anticipates capital expenditures $1,717,000 for this program. No O&M expenses are expected for this program for 2008.

Q. Please describe how Tampa Electric reached the decision to sell SO_2 emission allowances in 2008 and discuss the company's allowance needs for 2008 and beyond.

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

In balancing the appropriate quantity to sell with the company's expected future needs, Tampa Electric will continue to evaluate potential sales opportunities of future quantities of surplus allowances.

Q. Please summarize your testimony.

A. Tampa Electric's settlement agreements with FDEP and EPA require significant reductions in emissions from Tampa Electric's Big Bend and Gannon Stations. The Orders established definite requirements and time frames in which air quality improvements must be made and result in reasonable and fair outcomes for Tampa Electric, its community and customers, and the environmental agencies. My testimony identified projects, which are legally required by these Orders. I described the progress Tampa Electric has made to achieve the more stringent environmental standards. I have identified estimated costs, by project, which the company expects to incur in 2008. Additionally, my testimony identified other projects that are required for Tampa Electric to meet the environmental requirements and I provided the associated 2008 activities and projected expenditures. Finally, I addressed the prudent sales of SO_2 emissions allowances that are anticipated to occur in 2008 and demonstrated that Tampa Electric's approach toward the allowance quantity contained in the sales will not jeopardize the company's long-term future allowance needs.

Q. Does this conclude your testimony?

A. Yes it does.

MS. BROWN: Madam Chairman, as mentioned before, since the parties are proposing stipulated positions on all the issues, we suggest that the Commission can make a bench decision in the case. And that being said, we recommend that the proposed stipulations in Section VIII of the Prehearing Order, Pages 6 through 13, with the additional stipulated language for Issue 10A be approved.

CHAIRMAN EDGAR: Okay. Ms. Brown, do we need to enter the proposed stipulation for 10A?

MS. BROWN: Yes. Yes.

CHAIRMAN EDGAR: Did I get ahead of you? I'm sorry.

MS. BROWN: No. That's all right.

Madam Chairman, yes, that language for the Issue 10A reads, "Should the Commission approve PEF's updated Integrated Clean Air Compliance Plan filed as a reasonable and prudent means to comply with the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR) and Clean Air Visibility Rule (CAVR) and related regulatory requirements?" And the position now, stipulated position to that issue reads, "Yes. PEF's updated Integrated Clean Air Compliance Plan represents the most cost-effective alternative for achieving and maintaining compliance with CAIR, CAMR and CAVR, and related regulatory requirements, and it is reasonable and prudent for PEF to recover prudently incurred costs to implement the plan. PEF shall file as part of its true-up testimony in the

Environmental Cost Recovery Clause a yearly review of the efficacy of its Plan D and the cost-effectiveness of PEF's retrofit options for each generating unit in relation to expected changes in environmental regulations." And with that, Madam Chairman, we ask that you approve the proposed stipulations.

CHAIRMAN EDGAR: Okay. Let me back up for just a moment. The changes to the factors, do we need to address that?

MS. BROWN: Yes. That's right. I'm sorry.

CHAIRMAN EDGAR: That's okay.

MS. BROWN: We have those changes that I mentioned, and Mr. Butler is prepared to make them for you.

CHAIRMAN EDGAR: Mr. Butler, can you address the proposed changes to the factors?

MR. BUTLER: I will. Thank you, Madam Chairman.

In the course of discovery we realized that we had an overprojection for the costs in January of 2008 for our St. Lucie Cooling Water System Inspection and Maintenance Project. They were $442,000. They are now $300,000. And this affects Issues 3, 4 and 7.

The position for Issue, excuse me, 3 should be for FPL $44,571,921 instead of the $44,712,161.

For Issue 4 it should be $43,625,286 instead of $43,765,627.

And then finally, even though this is a very small change, it just tipped the scale on a couple of the rate class factors. So on Issue 7 the rate, the ECRC factor for the ISST1D rate that's shown there as .00036 should be .00035. And then the same change down three, three factors below or three rate classes below the SST1D1/, et cetera, should be 0.00035.

CHAIRMAN EDGAR: Thank you, Mr. Butler.

Ms. Brown, do we need to enter those changes to the factors into the record or is Mr. Brown (sic.) reading them into the record sufficient? Or Mr. Butler. Excuse me. Sorry.

MS. BROWN: I think Mr. Butler reading them into the record is sufficient.

CHAIRMAN EDGAR: Okay.

MS. BROWN: And we'll reflect that in the final order.

CHAIRMAN EDGAR: Okay. Any other matters that need to be addressed before we move to the proposed stipulations?

MS. BROWN: I think that's it.

CHAIRMAN EDGAR: Okay. Are you recommending a bench decision?

MS. BROWN: Yes. We're recommending a bench decision, which would involve approval of all the proposed stipulations.

CHAIRMAN EDGAR: Okay. Commissioners, as you've heard, our staff is recommending a proposed -- is recommending

a bench decision, recognizing that all witnesses have been excused and we have proposed stipulations on all issues. We have proposed stipulations for Issues 1 through 8, 9A through 9G, noting the changes to the factors from Mr. Butler and also the stipulated language that Ms. Brown read into the record for Issue 10A. And so with that, are there any questions? Seeing none, is there a motion to adopt the proposed stipulations as I have described?

COMMISSIONER CARTER: So move.

COMMISSIONER SKOP: Second.

CHAIRMAN EDGAR: All in favor, say aye. Aye.

(Unanimous affirmative vote.)

Opposed? Show it adopted.

Any other matters for this docket?

MS. BROWN: The only other matter is that the final order will be issued by November 26th, 2007.

CHAIRMAN EDGAR: Thank you. And as just noted, the final order in this docket will be issued by November 26th. And that concludes the record and the hearing for the 07 docket. Thank you.

(Hearing concluded at 10:06 a.m.)

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

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

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

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

DATED THIS 16th day of November, 2007.

Linda Boles

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

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
Staff				
1		Exhibit List-Stip-1	Comprehensive Exhibit List	
2		Staff Composite Exhibit Stip-2	**Florida Power & Light** 1. FPL's Response to Staff's 1st Set of Interrogatories (Nos. 1 – 23). 2. FPL's Response to Staff's 3rd Set of Interrogatories (Nos. 33 - 35). 3. FPL's Response to Staff's 4TH Set of Interrogatories (No. 36 - 47). 4. FPL's Response to Staff's 5th Set of Interrogatories (Nos. 48 - 65). 5. FPL's Response to OPC's 1st Set of Interrogatories (Nos. 1 – 14). 6. FPL's Response to Staff's 2nd Request for Production of Documents (Nos. 2 & 3). 7. FPL's Response to Staff's 3 rd Request for Production of Documents (No. 4 – FPL Bates Stamp pages 07-009 – 07-0010 and 07-0023 – 07-0029) and No. 11. 8. FPL's Response to Staff's 4th Request for Production of Documents (No. 12).	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 1
COMPANY FPSC Staff
WITNESS Exhibit List-Stip-1
DATE 11-06-07

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
			9. Panel Deposition Transcript of Dubin / LaBauve of 10/25/07 and Late Filed Exhibit (Nos. 1 - 4). **Progress Energy Florida** 10. PEF's Response to Staff's 1st Set of Interrogatories, No. 1 to 25 (incl. Attachment 4.) 11. PEF's Response to Staff's 2nd Set of PODs, No. 8 (PEF Bate Stamp Pages 02132 to 02155 and pages 03252 to 03256). 12. Panel Deposition Transcript of Cornell/Waters (10/24/07) with Late Filed Exhibit No. 1. 13. Deposition Transcript of Patricia West (10/19/07). **Gulf Power Company** 14. Gulf 's Response to Staff's 1st Set of Interrogatories, Nos. 1-17.	
3		**Confidential** Staff Composite Exhibit - 3	**Florida Power & Light Company** 1. FPL's Response to Staff 4th Set of Interrogatories, (pages 1, 6, 19-27) and No. 40.	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
			Progress Energy Florida 2. PEF's Response to Staff's 1st Set of Interrogatories, No. 5 (including Attachment 5) and No. 22. 3. PEF's Response to Staff 2nd Set of PODs, No. 2 (PEF Bate Stamp Pages 00001 to 00004) and No. 4 (PEF Bate Stamp Pages 02156 to 02160).	
Testimony Exhibit List				
FLORIDA POWER & LIGHT				
4	K. M. Dubin	KMD-1	Appendix I Environmental Cost Recovery Final True-up January - December 2006 Commission Forms 42 - 1A through 42 - 8A	
5	K. M. Dubin	KMD-2	Appendix I Environmental Cost Recovery Estimated/Actual Period January-December 2007 Commission Forms 42-1E through 42-8E	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
6	K. M. Dubin	KMD-3	Appendix I Environmental Cost Recovery Projections January - December 2008 Commission Forms 42-1P through 42-7P and revised 2007 Estimated/Actual True-up Amount	
7	R. R. LaBauve	RRL-1	Florida Department of Environmental Protection Rule 62.550.310, Florida Administrative Code – Primary Drinking Water Standards: Maximum Contaminant Levels and Maximum Residual Disinfectant Levels	
8	R. R. LaBauve	RRL-2	Consent Order in OGC Case Number 06-0744 FPL Martin Plant Public Water System PWS #4431748	
9	R. R. LaBauve	RRL-3	Golder Associates Inc. FPL Martin Plant Potable Water System DBP (THM & HAA5) Analysis	
10	R. R. LaBauve	RRL-4	Department of Environmental Protection – Letter approving Corrective Action Plan for FPL Martin Plant PWS #4432748	
11	R. R. LaBauve	RRL-5	Clean Air Interstate Rule – Summary of FPL 800 MW Unit Cycling Project	
12	R. R. LaBauve	RRL-6	Clean Air Interstate Rule – Summary of FPL Peaking Gas Turbine CEMS	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
13	R. R. LaBauve	RRL-7	Clean Air Visibility Rule – Update Summary of FPL BART Project	
14	R. R. LaBauve	RRL-8	Clean Air Visibility Rule – Florida Department of Environmental Protection – Reasonable Progress Rule Workshop Slides	
15	R. R. LaBauve	RRL-9	10 CFR Part 20, Subpart K – Nuclear Regulatory Commission – Waste Disposal	
16	R. R. LaBauve	RRL-10	South Carolina State Statutes – Title 48 – Environmental Protection and Conservation, Chapter 46 – Atlantic Interstate Low-Level Radioactive Waste Compact Implementation Act	
17	R. R. LaBauve	RRL-11	10 CFR Part 50, Subpart 54 – Nuclear Regulatory Commission – Conditions of Licenses	
PROGRESS ENERGY FLORIDA				
18	Will Garrett	WG-1	PSC Forms 42-1A through 42-8A January 2006 – December 2006	
19	Will Garrett	WG-2	Capital Program Detail January 2006 – December 2006	
20	Patricia Q. West	PW-1	PEF Environmental Cost Recovery Clause 2008 CAIR/CAMR Projects Summary	
21	Thomas Cornell	TC-1 Confidential	Organization chart showing PEF internal management structure for Integrated Clean Air Compliance Plan	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
22	Thomas Cornell	TC-2 Confidential	Organization chart showing PEF structure for management and oversight of contractors involved in the Crystal River CAIR projects	
23	Thomas Cornell	TC-3 Confidential	Composite Exhibit consisting of Letter of Intent (LOI) to enter an EPC with Environmental Projects Crystal River, along with four amendments to the LOI	
24	Thomas Cornell	TC-4 Confidential	Composite Exhibit consisting of contract with The Babcock and Wilcox Company ("B&W"), as well as associated work authorizations, for design, engineering, equipment, and other work associated with the Crystal River SCR and FGD projects	
25	Thomas Cornell	TC-5 Confidential	Composite Exhibit consisting of contract with Worley Parsons (and associated work authorizations) for preliminary design, engineering and other work associated with the Crystal River SCR and FGD projects	
26	Thomas Cornell	TC-6 Confidential	Contract with The Stebbins Engineering and Manufacturing Company for design, fabrication, construction, and assembly of two FGD Absorber Towers for Crystal River Units 4 and 5	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
27	Thomas Cornell	TC-7 Confidential	Contract with CERAM Environ-mental, Inc. for the design, fabrication, delivery, and testing of the SCR catalyst for the Crystal River Units 4 and 5 SCR projects	
28	Thomas Cornell	TC-8 Confidential	Contract with Commonwealth Dynamics, Inc., for the design, fabrication, and construction of a Flue Gas Chimney as part of the Crystal River Units 4 and 5 scrubber projects	
29	Thomas Cornell	TC-9 Confidential	Contract with Environmental Projects Crystal River	
30	Samuel Waters	SSW-1 Confidential	Progress Energy Florida Integrated Clean Air Compliance Plan –6/01/07	
31	Samuel Waters	SSW-2 Confidential	Summary of Alternative Compliance Plans – 2006	
32	Samuel Waters	SSW-3 Confidential	Summary of Alternative Compliance Plans - Current	
33	Samuel Waters	SSW-4	Comparison of Cumulative Present Value of Revenue Requirements	
34	Samuel Waters	SSW-5	Impact of Allowance Price Uncertainty	
35	Maritza Iacono	MI-1	PSC Forms 42-1E through 42-8E January 2007 – December 2007	
36	Maritza Iacono	MI-2	Capital Program Detail January 2007 – December 2007	
37	Maritza Iacono	MI-3	Modular Cooling Tower Cost Breakdown	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
38	Maritza Iacono	MI-4	PSC Forms 42-IP through 42-7P January 2008 – December 2008	
39	Maritza Iacono	MI-5	Capital Program Detail January 2008 – December 2008	
GULF POWER COMPANY				
40	R. J. Martin	RJM-1	Calculation of Final True-up 1/06 – 12/06	
41	R. J. Martin	RJM-2	Calculation of Estimated True-up 1/07 – 12/07	
42	R. J. Martin	RJM-3	Calculation of Projection 1/08 - 12/08	
TAMPA ELECTRIC COMPANY				
43	Howard T. Bryant	HTB-1	Final Environmental Cost Recovery Commission Forms 42-1A through 42-8A for the period January 2006 through December 2006	
44	Howard T. Bryant	HTB-2	Final Environmental Cost Recovery Commission Forms 42-1E through 42-8E for the period January 2007 through December 2007	
45	Howard T. Bryant	HTB-3	Forms 42-1P through 42-7P for the period January 2008 through December 2008	

Exhibit #	Witness	Counsel	Description	Moved In/Due Date of Late Filed

Exhibit #	Witness	Counsel	Description	Moved In/Due Date of Late Filed
46				
47				
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49				
50				
51				
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EXHIBIT NO. _____

DOCKET NO: 070007-EI

WITNESS: VARIOUS

PARTY: FLORIDA POWER & LIGHT CO.
PROGRESS ENERGY FLORIDA
TAMPA ELECTRIC COMPANY
GULF POWER COMPANY

DESCRIPTION: COMPOSITE EXHIBIT -2 OF STIPULATED NON-CONFIDENTIAL **(Redacted)** DOCUMENTS:

Florida Power & Light

1. FPL's Response to Staff's 1st Set of Interrogatories (Nos. 1 – 23).
2. FPL's Response to Staff's 3rd Set of Interrogatories (Nos. 33 - 35).
3. FPL's Response to Staff's 4TH Set of Interrogatories (No. 36 - 47).
4. FPL's Response to Staff's 5th Set of Interrogatories (Nos. 48 - 65).
5. FPL's Response to OPC's 1st Set of Interrogatories (Nos. 1 – 14).
6. FPL's Response to Staff's 2nd Request for Production of Documents (Nos. 2 & 3).
7. FPL's Response to Staff's 3 rd Request for Production of Documents (No. 4 – FPL Bates Stamp pages 07-009 – 07-0010 and 07-0023 – 07-0029) and No. 11.
8. FPL's Response to Staff's 4th Request for Production of Documents (No. 12).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI **EXHIBIT** 2
COMPANY FPSC Staff
WITNESS Staff Composite Exhibit Stip2
DATE 11-06-07

9. Panel Deposition Transcript of Dubin / LaBauve of 10/25/07 and Late Filed Exhibit (Nos. 1 - 4).

Progress Energy Florida

10. PEF's Response to Staff's 1st Set of Interrogatories, No. 1 to 25 (incl. Attachment 4.)

11. PEF's Response to Staff's 2nd Set of PODs, No. 8 (PEF Bate Stamp Pages 02132 to 02155 and pages 03252 to 03256).

12. Panel Deposition Transcript of Cornell/Waters (10/24/07) with Late Filed Exhibit No. 1.

13. Deposition Transcript of Patricia West (10/19/07).

Gulf Power Company

14. Gulf 's Response to Staff's 1st Set of Interrogatories, Nos. 1-17.

PROFFERED BY: STAFF

Florida Power & Light's Responses to

Staff's 1st ROGS Nos. 1 - 23

070007

Q.

On Page 3 of Randall Labauve's direct testimony of August 3, 2007, he states FPL has tried unsuccessfully for several years to bring the drinking water system at the Martin Plant into compliance with Rule 62-550.310(3), FAC. What were the actions taken by the company to come into compliance with the rule, and when were such actions taken?

A.

Initial ground water results at the Martin Plant indicated the required water quality could possibly be achieved with the original treatment system. The targeted values were 80 parts per billion (ppb) total trihalomethanes (TTHMs) and 60 parts per billion (ppb) haloacetic acids (five) (HAA5) respectively. The initial sample was higher than the target levels, and subsequent results show some variability, but have continued to exceed target levels for several years.

Experts from the Florida Rural Water Association were contacted in early 2004 and FPL implemented their recommended countermeasures. This included post chlorination to form precursors which would then be removed by the existing carbon bed and aerator. None of the recommended countermeasures lowered the numbers below the target limits.

When none of the recommended countermeasures improved the process FPL hired an independent consultant. Golder Associates Inc. assisted in the evaluation of our system and a draft plan that could be implemented to make the existing system capable of treating these components. The Golder Associates review concluded that the two Disinfectant By Product (DBP) treatment technologies within the Martin drinking water system, namely aeration and activated carbon filtration are presently the best technologies for the removal of DBPs. The report concluded either the carbon bed or the aerator would have to be replaced with newer, larger versions.

Q.

How long has FPL been using liquid sodium hypochlorite as its method of drinking water disinfection at the Martin site?

A.

FPL has been using liquid sodium hypochlorite for drinking water disinfection at the Martin Plant since 1988.

Q.

Has FPL considered disinfection via chloramines to lower the levels of THMs and HAA5s?

A.

Chloramines have been considered as an option to lower TTHMs, but they are only expected to reduce concentrations by approximately 50%. While this would be an improvement, it cannot be depended upon to be adequate given the variability of the groundwater pollutant concentrations.

Q.
If yes, why was the chloramine disinfection method not chosen?

A.
See response to Interrogatory No. 3, above.

Q.
If no, why was the chloramine disinfection method not considered?

A.
NA.

Q.

Is the reason for additional treatment now being needed that the levels of THMs and HAA5s in FPL's potable water supply have increased?

A.

The additional treatment is to comply with the requirements of the rule that came into effect in 2004. FPL's extended but ultimately unsuccessful effort to comply with those requirements while using our existing water treatment system culminated in the 2006 FDEP consent order.

Q.

Is the reason for additional treatment now being needed that the MCL [maximum contaminant level] has changed and therefore the former level in the potable water system no longer meets standards? Explain.

A.

See response to Interrogatory No. 6 above.

Q.

What alternative methods of treatment have been considered to lower the level of THMs and HAA5s other than the recommended modifications to the existing Martin site drinking water system?

A.

Alternatives considered were chlorine dioxide, ultra violet light, and ozone, as well as the use of chloramines as discussed in the answer to Interrogatory No. 3.

Q.
Please explain why each of the other alternatives considered was not selected.

A.
Chlorine dioxide does not produce TTHMs, but produces chlorite, which is also regulated under the Disinfection Byproduct rule. Therefore we could be introducing another disinfection byproduct above the maximum contaminant limit.

Ozone or UV cannot be used because neither leaves residual chlorine, which is required in the drinking water treatment system.

Chloramine is discussed in the response to Interrogatory No. 3 above.

The treatment system that was selected is also less costly than the other alternatives listed above.

Q.
Why is the modification to the existing system considered to be the best available treatment technology for the potable water system?

A.
Based on our discussions with other water professionals, switching to an alternative would not be expected to be as effective at improving the existing treatment system.

See the responses to Interrogatory Nos. 3 and 9 above.

Q.
Approximately how much drinking water is used at the Martin site each year?

A.
The Martin Plant uses approximately 2.8 million gallons of drinking water per year.

Q.
How many employees work at Martin Site?

A.
The Martin Plant has 109 FPL employees.

Q.
Approximately how many visitors visit the Martin site each year?

A.
Approximately 800 visitors per year, including contractors.

Q.
What are the uses of the drinking water system other than for human consumption?

A.
In addition to human comsumption, potable water is also used for restrooms, showers and laundry.

Q.

What is the nearest alternative drinking water system to the Martin site to which FPL could connect?

A.

The closest connection to an alternative drinking water system is in Indiantown, and that system is approximately 1.5 miles away.

Q.

What does FPL estimate the cost would be to connect to the nearest alternative drinking water system to the Martin site? How did it derive that estimate?

A.

An engineering estimate was generated in 1998, to install 4" HDPE Potable and Sewage pipelines to the nearest connection point on the Indiantown system. In 1998 dollars the estimate was $450,000. This included $171,114 for a potable line, $192,464 for a sewage line, and $74,248 for enginering contingencies. Of course, the cost to connect today likely would be higher due to escalation.

Q.

Why does the proposed modification to the existing Martin drinking water system comply with the requirements of the Environmental Cost Recovery Clause for cost recovery purposes?

A.

The criteria for ECRC cost recovery was established by the Commission in Order No. 94-0044-FOF-EI, issued on January 12, 1994, in that:

(a) all expenses are prudently incurred after April 13, 1993;

(b) the activities are legally required to comply with a governmentally imposed environmental regulation that was created, became effective, or whose effect was triggered after the company's last test year upon which rates are based; and

(c) none of the expenditures are being recovered through some other cost recovery mechanism or through base rates.

In response:

(a) Expenses related to FPL's Martin Plant Drinking Water System Compliance Project for which FPL is requesting ECRC recovery will be incurred beginning in October 2007.

(b) The Martin Plant Drinking Water System Compliance Project is required per the Florida Department of Environmental Protection (FDEP) Rule 62-550.310(3), Florida Administrative Code and FPL's Consent Order with the FDEP that was signed on September 22, 2006. FPL's last test year upon which its current rates are based is 2006.

(c) None of the expenses related to FPL's Martin Plant Drinking Water System Compliance Project for which FPL is requesting ECRC recovery are being recovered through any other mechanism or through base rates.

Q.

Are the pollutants addressed by Rule 62-550.310(3) F.A.C. at the Martin site caused by power generation, distribution, or transmission?

A.

No.

Q.

Does FPL believe that definition of environmental laws and regulations referenced Section 366.8255, F.S. include those laws or regulations unrelated to the environmental impacts of power generation, distribution, and transmission functions? If so, why?

A.

Per Section 366.8255 (1) (c), Florida Statutes, FPL believes that "Environmental laws or regulations" includes 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." This definition does not limit the electric utility functions to which it applies. See also the answer to Interrogatory No. 20.

Q.

Please site instance wherein the commission allowed recovery via the ECRC of costs to address environmental impacts unrelated to power generation, distribution, and transmission function?

A.

FPL is unaware of any approved ECRC projects addressing environmental impacts that do not relate in some way to the generation, transmission or distribution of electricity. This is not surprising, given that an electric utility's business is fundamentally the generation, transmission and distribution of electricity. The implication of Staff Interrogatory No. 20 appears to be that ECRC cost recovery is limited to projects undertaken to comply with environmental requirements that are directly attributable to the emission or discharge of some sort of pollutant from a utility facility. FPL does not believe that this would be an accurate characterization of what section 366.8255 provides. The statute allows cost recovery for "all costs or expenses incurred by an electric utility in complying with environmental laws or regulations" and then defines "environmental laws or regulations" to be "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.*" (Emphasis added). This clearly applies to environmental requirements with which an electric utility must comply irrespective of whether the requirements are the direct result of the utility's emitting or discharging a pollutant from one of its facilities. The Martin Plant Drinking Water System Compliance Project clearly relates to actions FPL is being directed to take by an environmental agency pursuant to environmental laws or regulations and, as such, the prudent compliance costs FPL incurs for that project are eligible for ECRC recovery.

FPL notes that the Commission has approved several other ECRC projects addressing environmental impacts that only indirectly relate to the generation, transmission or distribution of electricity. For example, Progress Energy Florida has an approved Sea Turtle - Coastal Street Lighting project that requires Progress to take certain measures to limit the impact of lights that it owns on turtle nesting areas. The only "pollutant" being addressed by that project is light, which is at most an indirect consequence of the generation, transmission and distribution of electricity. Gulf Power Company has an approved Asbestos Fees project for fees incurred in removing asbestos from its facilities. There is no suggestion that the asbestos was emitted or discharged by Gulf's facilities, but because it was used as a construction material in facilities that Gulf owns and there are environmental requirements associated with its removal, the associated fees are ECRC recoverable. Perhaps most relevant here, Gulf also has a Lead & Copper Rule project to recover the costs of treating and sampling potable water supplies for lead and copper. This appears to be directly analogous to the nature and purpose of FPL's Martin Plant Drinking Water System Compliance Project .

Q.

Are the costs of the existing aeration and carbon filtration used to treat the drinking water at the Martin site currently recovered in base rates? If so, what is the recovery amount (annualized) and what historical filing(s) document that recovery amount?

A.

Yes, those costs are recovered in base rates. The amount included in the 2006 budget for replacement of the carbon filtration media is $10,000. This amount is in Schedule C-6, included under FERC Account Nos. 511 through 514 - Steam Power Maintenance, filed in Docket 050045-EI, re: Petition for Rate Increase by Florida Power & Light Company, on March 22, 2005.

Q.

What was the purpose of the existing aeration and carbon filtration system in use today designed in part to mitigate the pollutants that FPL proposed to treat with the modified system? Explain.

A.

The existing aeration system was designed to strip volatile organics out of the water, while the activated carbon removes them by absorption. The efficacy of these systems depends on both containment concentrations in the groundwater to be treated, as well as the required rate of throughput. Golder Associates Inc. indicated that the aeration process should work well provided the blower or air stripper could produce enough air. In addition the carbon bed can be expected to remove both of the compounds in question, but the size of the unit would have to be increased.

Q.

Was the environmental requirement referenced as the impetus of the Martin Plant Drinking Water System Compliance Project (Rule 62-550.310(3)) enacted after FPL's last rate case, effective after the last rate case, or was its effect triggered after the last rate case? Please explain.

A.

The environmental requirement necessitating the Martin Plant Drinking Water System Compliance Project is the FDEP's September 22, 2006 Consent Order, which imposes certain corrective actions in order to ensure that the drinking water system complies with Rule 62-550.3110(3) F.A.C. It was not until the Consent Order that FPL was required to conduct the pilot test and implement the modifications that are the subject of this Project. Therefore, FPL did not project costs for those activities in its most recent (i.e., 2006) base rate MFRs, nor could FPL reasonably have been expected to do so.

Florida Power & Light's Responses to

Staff's 3rd ROGS Nos. 33 - 35

070007

Q.

Please refer to the testimony page 5, line 19 though 22. Does FPL currently recover disposal expenses through base rates? If so, what will be the impact on base rates if FPL constructs its own Low Level Radioactive Waste Storage? Does FPL propose to net expenses recovered through base rates against O&M and depreciation expense incurred as a result of the provision of on-site storage for Low Level Radioactive Waste?

A.

Yes, disposal costs are currently recovered through base rates. As described below, there will be no impact on base rates if FPL constructs its own Low Level Radioactive Waste Storage Facility.

No, there is no occasion for netting. In accordance with the current Generally Accepted Accounting Principles (GAAP), FPL accrues the costs for disposal of its Low Level Waste (LLW) when the LLW is first generated. As stated above, this amount is included in base rates. It is appropriate that disposal costs will not be offset against costs associated with the LLW Storage Project because FPL remains responsible for disposing of that LLW at some future date. In the absence of more specific information, FPL is currently accruing disposal costs based on the existing Barnwell disposal fees. FPL expects that the ultimate actual disposal cost will be at least as much as the accruals, because it does not appear likely at this time that a new disposal facility would charge lower fees than what is currently being charged at Barnwell. The incremental costs for constructing the facility and ongoing maintenance costs are being requested for recovery.

Q.

Please refer to the testimony page 6, line 10 through 13. Were past interim storage plans prepared during the 1990s as referenced addressed in any proceedings before the FPSC? If so, please identify those dockets and the resulting decisions, if any. Has this issue been addressed in any other proceedings, either docketed or undocketed by the FPSC? If so, please identify the proceedings.

A.

The interim storage plans have not been discussed in detail previously. However, they were mentioned in the testimony of FPL witness William M. Reichel filed with the Commission on July 7, 1993. FPL requested ECRC recovery of access fees for the disposal of FPL's low-level radioactive waste at the Barnwell facility in South Carolina. In his testimony, Mr. Reichel stated "If we choose not to pay the fees we would be denied access to the Southeast region's low-level radioactive waste disposal facility. FPL would then have to construct and operate on-site storage facilities for low-level radioactive waste. There are no other facilities that can accept FPL's low-level radioactive waste. In addition, the Nuclear Regulatory Commission has also proposed a rule to be effective after January 1996 which would make it a violation to store waste on-site whenever disposal is otherwise available. Nonetheless, FPL calculates that implementing on-site storage for low-level radioactive waste for a five-year period would cost an additional $6.1 million. The differential cost for longer periods of on-site storage would be even higher". The recovery of FPL's Low-Level Radioactive Waste Access Fees Project was approved by the Commission in Order No. PSC-93-1580-FOF-EI, issued on October 29, 1993 in Docket No. 930661-EI. This issue has not been addressed in any other FPSC proceeding.

Q.

Please refer to the testimony beginning on page 8, line 24, and continuing through page 9, line 1, where FPL identifies projected capital costs of $1.5 million for 2008. Why is this cost not shown on Form 42-3p, pages 1 and 2, or on Form 42-4p, pages 39 and 40 of 45? When does FPL plan to begin depreciation associated with this project?

A.

FPL has projected capital expenses of $1.5 million in 2008, related to its proposed Low Level Radioactive Waste (LLW) Storage Project. FPL's preliminary in-service dates for LLW facilities at St. Lucie Units 1 & 2 and Turkey Point Units 3 & 4 are the end of 2009 and mid-2010, respectively, at which time depreciation and return on investment will begin, and will be recovered through the ECRC.

Florida Power & Light's Responses to

Staff's 4th ROGS Nos. 36 - 47

070007

Q.
For each of the CAIR and CAMR controls included in the March 30, 2007 FPL Supplemental CAIR/CAMR Filing:

A. Compare the total costs of the control, stated in terms of net present value, including a breakout of capital costs and O&M, versus the next most cost-effective, viable alternative.

B. Provide a timeline for the completion of each project.

C. Provide the annual reductions in emissions expected to be achieved by each project versus the current emissions.

A.

A. The CAIR and CAMR controls included in the March 30, 2007 FPL Supplemental CAIR/CAMR Filing are:

SJRPP – SCR with ammonia injection
SJRPP – Mercury CEMS
Scherer 4- Wet FGD Scrubber
Scherer 4- SCR with ammonia injection
Scherer 4- Mercury CEMS
Scherer 4- Fabric filter baghouse and mercury sorbant injection
800 MW cycling projects

Many of these CAIR and CAMR control projects have no viable alternatives. These projects are listed below:

- The mercury CEMS at SJRPP and Scherer 4 do not have alternatives as they are required to monitor the output level of mercury.

- The SCR controls at both Scherer 4 and SJRPP had no viable alternatives at the time the decision was made to install these controls. The installation of SCR controls on base load coal-fired steam boilers are considered by EPA as the most cost effective controls for the reduction of NOx emissions. The rules requiring the installation and operation of an SCR for NOx controls and an FGD for SO2 controls on Scherer Unit 4 were approved on June 27, 2007 by the Georgia DNR Board as an amendment to GA-391-3.

- The fabric filter baghouse and mercury sorbant injection at Scherer 4 was the technology specified for Scherer Unit 4 in the Amendments to the rules of the Georgia EPD relating to air quality, Chapter 391-3-01 and 391-3-02. The rules requiring the installation and operation of a baghouse for mercury

control on Scherer Unit 4 were also approved in the June 27, 2007 amendment of GA-391-3 by the Georgia DNR Board.

- The following project did have viable alternatives. See discussion below:

- The wet FGD scrubber at Scherer 4 did have a viable alternative: dry FGD scrubber technology. A consultant of Southern Company completed a study which showed that, based on lifecycle costs, the wet FGD scrubber was the more economic choice at Scherer 4. This study is included as Attachment I.

- And finally, for the 800 MW Cycling Project, FPL did not identify a viable alternative (other than a "do not implement" or "do nothing" alternative). The 800 MW project, in addition to substantial emission savings, produces large fuel savings which would make it more cost effective than any other control technology under consideration for FPL's CAIR compliance strategy. The economics of this project vs. the "do nothing alternative" are shown in response to Staff POD No. 11.

B. FPL's estimates for the completion of each project are as follows:

- **Installation of an SCR and Ammonia Injection System on SJRPP Unit 1 -** Currently scheduled for an in-service date of May 01, 2009.

- **Installation of an SCR and Ammonia Injection System on SJRPP Unit 2 -** Currently scheduled for an in-service date of May 01, 2008.

- **Installation of a FGD (Flue Gas Desulfurization) on Scherer Unit 4 -** Currently scheduled for an in-service date of April 08, 2012.

- **Installation of an SCR and Ammonia Injection System on Scherer Unit 4** - Currently scheduled for an in-service date of April 08, 2012.

- **Installation of a Fabric Filter Bag House and Mercury Sorbent Injection System on Scherer Unit 4 -** Currently scheduled for an in-service date of April 04, 2012.

- **Installation of a Mercury CEMS on Scherer Unit 4 -** Currently scheduled for an in-service date of March 01, 2008.

- **Installation of a Mercury CEMS on SJRPP Unit 1 -** Currently scheduled for an in-service date of December 01, 2007.

- **Installation of a Mercury CEMS on SJRPP Unit 2 -** Currently scheduled for an in-service date of December 01, 2007.

- **800 MW Cycling Project -** This is being completed in numerous stages as scheduled unit outages on the four effected units are completed. The project consists of numerous small items that can be completed separately in an efficient and cost effective measure, which minimizes system impact. At the current time, the estimated completion time of all aspects of the project is the summer of 2010.

C. Attachment II shows the annual reductions in emissions expected to be achieved by each project versus the current emissions.

SOUTHERN COMPANY

Energy to Serve Your World®

Southern Company Services, Inc.
Plant Scherer FGD Project

FGD Process Selection Study
Comparative Evaluation of Wet and Dry Scrubbing

SCHR-1-LI-021-0001
Rev. B

Nov. 2006

WorleyParsons
resources & energy

Appendices

A. Basic Design Basis – Wet FGD
B. Basic Design Basis – Dry FGD
C. Flue Gas Flow Diagrams
D. Conceptual Process Design – Wet FGD
E. Conceptual Process Design – Dry FGD
F General Arrangements – Wet FGD
G. General Arrangements – Dry FGD
H. Life Cycle Cost Spreadsheets – Wet FGD
I. Life Cycle Cost Spreadsheets – Dry FGD
J. Basis of the Capital Cost Estimates
K. Project Capital Cost Estimates – Wet & Dry FGD
L. Major Equipment Lists – Wet & Dry FGD
M. Project Milestone Schedules – Wet & Dry FGD
N. Electrical Single-Line Diagrams - Wet & Dry FGD

1. EXECUTIVE SUMMARY

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Approach

Plant Scherer is a four-unit, coal-fired electric generating facility that currently fires a low-sulfur Powder River Basin (PRB) coal. The units are not presently equipped with flue gas desulfurization (FGD) facilities. By the years 2010 and 2015, the Clean Air Interstate Rule (CAIR) requires system-wide reductions in sulfur dioxide emissions. At Plant Scherer, it is planned to install FGD facilities that will achieve a minimum 95% reduction in SO_2 emissions.

An initial screening study by Southern Company Generation identified two candidate FGD technologies that held the highest potential for successful application to Plant Scherer. The FGD processes so identified, and evaluated further in the present study, were the following:

- Limestone Forced Oxidation (LSFO), i.e., wet FGD, and
- Lime Spray Drying (LSD), i.e., dry FGD.

The current evaluation includes an increased level of engineering detail to support the capital cost estimates and to provide a more comprehensive, quantitative comparison of the two alternative FGD technologies being considered. Two coals were specified for the design basis: the present PRB coa with a 0.3%-S contentl, and a Central Appalachian (CAPP) bituminous coal with a 1.5%-S content. The CAPP coal was specified as the basis of the facility design and study evaluation, and the PRB coal was evaluated as an alternative case.

The primary tool for quantitative evaluation of the alternative technologies was the calculation of net present values (NPV's) for each alternative's life cycle costs. These costs included capital, for project design/construction, and operating & maintenance for 20 years of FGD facility operations. The results, for the two study coals, are as follows.

A B C D E

[redacted]

Recommendation

The comparison of the net present value costs of the two FGD technologies considered in this study shows that the LSFO, or wet, technology has a significantly lower life cycle cost than the lime spray drying, or dry, technology for Scherer. Therefore it is recommended that Southern Company proceed with the installation of a wet type process to meet the SO_2 emission limits for Plant Scherer.

2. INTRODUCTION

Plant Scherer is a four-unit, coal-fired electric generating facility that currently fires a low-sulfur Powder River Basin (PRB) coal. The units are not presently equipped with flue gas desulfurization (FGD) facilities. By the years 2010 and 2015, the Clean Air Interstate Rule (CAIR) requires system-wide reductions in sulfur dioxide emissions. At Plant Scherer, it is planned to install FGD facilities that will achieve a minimum 95% reduction in SO_2 emissions.

An initial screening study was performed by Southern Company of means to meet this SO_2 emission reduction target. The study identified two candidate FGD technologies for application at Scherer: a wet scrubbing process (limestone forced oxidation) using limestone reagent, and producing gypsum byproduct; and a dry scrubbing process (lime spray drying) using a lime-based reagent, and producing a dry by-product.

In the present study, WorleyParsons was commissioned to perform a more detailed evaluation of these two alternative flue gas desulfurization technologies for Plant Scherer, to develop a recommendation for implementation and to document the work process and results.

The primary tool for evaluation of the alternative technologies was the calculation of net present values (NPV's) of the life cycle costs for each of the two alternatives. The development of the components of the life cycle costs were based on

- Project-specific conceptual engineering,
- Site-specific operating & maintenance costs, and
- Financial parameters specific to Southern Company for Scherer.

The process evaluation also addressed consideration of qualitative and quantitative issues, such as:

- facility layout and maintenance access,
- space and constructability considerations,
- reagent receiving, handling & storage,
- FGD byproduct handling and storage/disposal, and
- process wastewater generation.

3. STUDY BASIS

3.1 Plant Description

Plant Scherer is located near Juliette, GA. The plant generating facilities consist of 4 near-identical coal-fired, steam-electric units, each with a nameplate rating of 818 MW. The units were placed in commercial service in succeeding years during the period 1982-1989. The steam generators are sub-critical, tangentially-fired, units that operate in balanced draft with a set of 2 FD fans, a set of 4 ID fans and cold-side electrostatic precipitators, each.

All four units currently fire a sub-bituminous Powder River Basin (PRB) coal, although Units 3 & 4 were originally designed for low-sulfur Central Appalachian coal. It is desired to maintain as much of this fuel flexibility as possible for future operations.

3.2 Conceptual Engineering Basis

3.2.1 Design Criteria

The key design criteria for the FGD facilities are tabulated in the Basic Design Basis documents in Appendices A (wet FGD) and B (dry FGD).

Of particular note in these criteria is the specification of two design coals: the current low-sulfur PRB coal (about 0.7 lb SO_2/MMBtu, 0.3% S) and a future Central Appalachian (CAPP) bituminous coal (about 2.3 lb SO_2/MMBtu, 1.5% S). The FGD facility, using either the wet or the dry process, is to be capable of operating with either coal while maintaining specified performance. Consequently, the sizing of gas-side components is dictated by the larger gas flow rate associated with the PRB coal, whereas sizing of the solid/liquid systems (*i.e.*, reagent handling, reagent prep, slurry handling, process water, etc.) is dictated by the larger sulfur content of the CAPP coal.

3.2.2 Air Quality Control Project Integration

In addition to these quantitative design criteria, a critical consideration in the planning and evaluation of the FGD project is the recognition of the sequence of air quality control (AQC) projects that is to be implemented at Scherer. These projects are depicted functionally in the flow diagrams in Appendix C (sketches SCHR-0-SK-253-305-001 through -005).

The current 'back-end' configuration is shown in the first sketch (-001). Flue gas exits the boiler casing at the economizer hopper and then passes successively through the air heaters, the electrostatic precipitators, the ID fans and is discharged to the stack. The flyash collected in the precipitator is recovered (by a third party contractor) for commercial sale.

The first AQC projects to be implemented will be the addition of facilities to each unit for removal of mercury from the flue gas (sketch -002). Here, the existing ductwork train will be broken between the discharge of the ESP's and the suction of the ID fans and the gas flow processed through new baghouses (or pulse jet fabric filters, PJFF's) following the injection of the active media, carbon. At this time, it is also planned to upgrade the ID fans by increasing their head capability to overcome the additional draft loss created by the new flue gas train components. After addition of the baghouses, it is planned to continue operation of the precipitators to support flyash sales commitments. (Note that collecting the flyash in the baghouses would result in flyash contamination with carbon.)

The next series of AQC projects will be the addition of selective catalytic reduction (SCR) systems to each unit for the removal of nitrogen oxides (sketch -003). For installation of this facility, the existing flue gas train will be broken between the economizer discharges and the air heater inlets, and the flue gas processed through SCR reactors following the injection of ammonia for NOx reduction. It is anticipated that the

upgrade of the ID fans, implemented during the mercury baghouse projects, will also provide sufficient head capability to operate the new SCR gas-side components.

The third and final phase of the AQC projects will be the addition of the FGD facility; the two alternatives are depicted in sketches -004 (wet FGD) and -005 (dry FGD).

- To install the wet FGD facility, the existing flue gas train on each unit will be broken at the discharge of the ID fans and new ductwork will feed the flue gas to a pair of booster fans, a single absorber vessel and exhaust through a new 'wet' dual-flue stack (common stack for each pair of units: 1&2, 3&4). A gas bypass path around each absorber is not included, but rather the existing stacks will be maintained for FGD system bypass operation via the indicated gas-side dampers.
- To install the dry FGD facility, a significant reconfiguration of the ductwork is required to achieve functional integration of the ID fans into the FGD facility. The baghouse supply and return ductwork (installed with the mercury control project) must be removed from tie-in points between the precipitators and ID fans, and reconstructed to originate from the discharge of the ID fans and to return to the existing stack. In addition, the supply ductwork must be reconstructed to incorporate the lime spray dryers. As with the wet system, a gas bypass path around the SO2-removal vessels (the spray dryers) is not included, but rather the ductwork incorporates a FGD system bypass.

3.2.3 Other

The retrofit of an FGD system to the Scherer boilers should also meet the following objectives.

- Comply with the emission requirements established by the state of Georgia for compliance with the Clean Air Interstate Rule (CAIR)
- Have minimal impact on other plant emissions
- Exhibit the lowest evaluated cost (net present value of 20-yr life cycle cost) of available alternatives
- Minimize plant impacts, such as unit capacity, efficiency, availability, and ramp rate, due to the operation of the FGD system

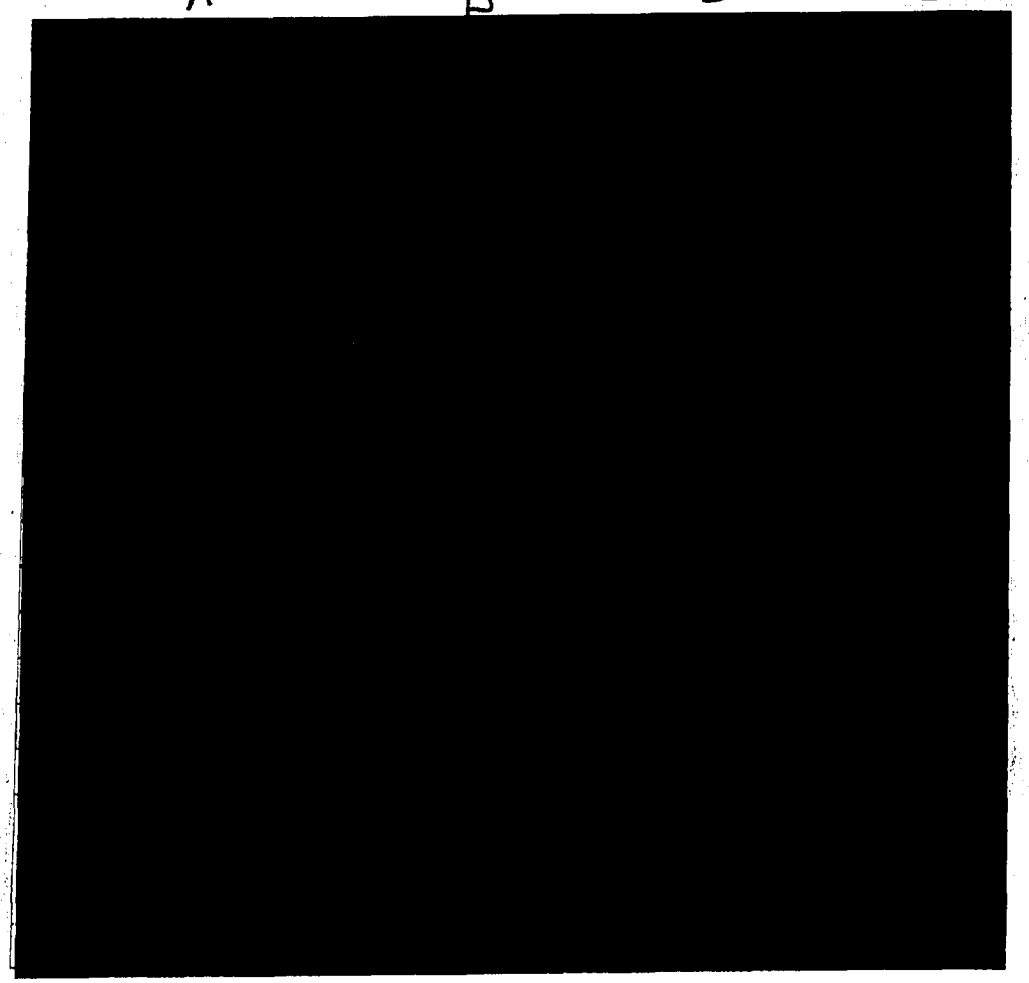
3.3 Economic Evaluation Criteria

The following parameters were used in the economic evaluation of the two alternative scrubbing technologies. All values were specified by Southern Company Generation, except as noted.

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Table 3-1
Economic Evaluation Parameters

A B C D



Note 1: Forecasted unit costs ($/T) for rail-delivered lime and limestone were provided year-by-year (by SoCo) for the time period 2011-2024. Extrapolated values (by WorleyParsons) were used for the time period 2025-2034. Specific values are listed in the spreadsheets contained in Appendices H and I.

Note 2: The present study is based on a gypsum handling process in which the absorber bleed slurry is pumped directly to a new, on-site gypsum pond, where the gypsum is allowed to settle out and the water recycled to the scrubbing operation. The cost of constructing the pond is included in the project capital cost. A cost of $100,000/yr has been assessed (by WorleyParsons) for (drag-line) stacking of the gypsum at the pond area and is included in annual O&M charges for the wet FGD facility.

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Note 3: The present study is based on (on-site) landfill of the dry FGD byproduct. The cost of constructing the landfill is included in the project capital cost. Costs for both labor and mobile equipment to haul the material to the landfill from the process area and to stack/compact it in the landfill are included in the annual O&M costs for the dry FGD facility as described in Section 5.2.

Note 4: Forecasted unit costs ($/T SO2) for SO2 credits were provided year-by-year (by SoCo) for the time period 2011-2024. Extrapolated values (by WorleyParsons) were used for the time period 2025-2034. Specific values are listed in the spreadsheets contained in Appendices H and I.

Note 5: The unit costs listed are an 'all-in' annual costs, that were derived (by WorleyParsons) from hourly salary rates (provided by SoCo), as described in Section 5.2.

Note 6: The values listed in the table were taken from year-by-year, unit-specific data provided by SoCo, and are the forecasted daily cost for the FGD tie-in year for each unit.

4. FGD SYSTEMS CHARACTERIZATION

4.1 Process Descriptions

The following section contains process descriptions of the two technologies chosen by Southern Company for potential retrofit on Plant Scherer to reduce SO_2 emissions. These technologies were chosen on the basis of SO_2 removal capability, commercial experience, current availability, compatibility with projected fuels, affect on current emission limits, byproduct management and reagent availability.

4.1.1 Limestone Forced Oxidation (LSFO) – Wet FGD Process

Refer to the process flow diagrams (SCHR-0-SK-021-305-001, SCHR-0-SK-021-305-002 & SCHR-0-SK-569-304-001) for the wet FGD process in Appendix D.

In the past 20 years, the LSFO process has evolved as the preferred wet FGD technology worldwide. LSFO offers the advantage of controlled oxidation of reaction products and potentially scale-free operation of the wet scrubber. Depending on process-specific conditions, LSFO may produce a salable byproduct in the form of commercial-grade synthetic gypsum that can be used for wallboard manufacturing or other industrial applications. A list of major equipment included in the LSFO facility is included in Appendix L.

Gas Scrubbing

In the LSFO process, hot flue gas exiting the ESP and ID/booster fans enters an absorber vessel where it is contacted with a dilute calcium carbonate and calcium sulfate slurry. The SO_2 reacts with the calcium carbonate in the limestone particles and the slurry drains into the reaction tank at the base of the vessel, where the neutralizing reactions are completed. After contact with the reagent spray, the flue gas continues an upward

vertical flow to multiple stages of mist elimination to remove the mist droplets from the gas stream. Then the flue gas exits the absorber through the outlet duct and discharges through the stack.

Within the reaction tank/absorber vessel, the calcium-bearing solids are suspended with agitators to facilitate the neutralization reactions. Fresh reagent and make-up water are periodically added as needed to keep the recirculation tank at optimum conditions for reactions to occur. Large slurry recirculation pumps are used to continually transport the slurry into the absorber vessel for reintroduction into the flue gas. Recirculation piping and spray nozzles provide fine slurry droplets within the flue gas stream to provide a large slurry droplet surface area to enhance the gas to liquid contact in the spray zone. As solids build-up in the reaction tank, bleed pumps maintain tank density to optimum conditions by transporting the solids to the dewatering process.

Generally, additives are not required in the LSFO process since the gypsum crystals resulting from this process tend to be relatively large, dense crystals that do not retain water. The solids coming from the dewatering process are typically 90%+ gypsum and inerts. This material is self-supporting and can be trucked, conveyed and moved using a front-end loader, or other conventional earth-moving equipment.

The LSFO process requires makeup water to replace the losses that occur through evaporation and the liquor entrained in the byproduct solids. Some of this makeup water can be supplied from any source that is not saturated with respect to any dissolved solids and contains a relatively low concentration of suspended solids. When producing a wallboard-grade gypsum product, the quality of the makeup water to the FGD system may have more restrictions than if the product solids were being sent to a landfill. For example, only low TDS/TSS water should be used for washing the gypsum cake to reduce chloride content and eliminate contamination of the gypsum byproduct. Chlorides must be maintained below a specified maximum concentration (as determined by material selection) to prevent excessive corrosion of wetted components.

The mist eliminator wash stream must be higher quality water to maintain scale-free operation. This intermittent wash water stream serves as a portion of the scrubber makeup water. If poor quality wash water is used for makeup, or if scrubber liquor is utilized, this typically will lead to heavy scale formation that can not be removed without taking the unit off-line for manual cleaning. In some cases, the use of saturated wastewater has led to the complete blockage of the mist eliminators.

The chemistry for this process begins with limestone ($CaCO_3$), the absorbing reagent, fed to the absorber reaction tank in an aqueous slurry at a molar feed rate of 1.03-1.05 moles of $CaCO_3$/mole of SO_2 removed. The major product of SO_2 reaction with limestone is the formation of hydrated calcium sulfite ($CaSO_3 \bullet \frac{1}{2}H_2O(s)$) according to the following reaction:

- $CaCO_3(s) + SO_2(g) + \frac{1}{2}H_2O \rightarrow CaSO_3 \bullet \frac{1}{2}H_2O(s) + CO_2$.

The sulfite is oxidized to sulfate by the injection of air into the bottom of the absorber sump, and then hydrated to form gypsum ($CaSO_4 \bullet 2H_2O$) through the following reaction:

- $CaSO_3 \bullet \frac{1}{2}H_2O(s) + \frac{1}{2}O_2 + 3/2H_2O \rightarrow CaSO_4 \bullet 2H_2O$.

In addition to the LSFO chemistry occurring in the absorber vessel and reaction tank, two other process steps are needed – reagent preparation and solids dewatering.

Reagent Preparation

As configured for the Scherer project, limestone is delivered by rail and discharged into a under-track hopper. From this hopper the limestone is conveyed and deposited on the storage pile by a radial stacker. A plant dozer will be used to move the limestone into a storage pile, and also to reclaim the limestone into the below-grade reclaim hopper. The reclaim system includes a vibrating feeder and conveyor system to transfer limestone to the day bins. Limestone day bins and feeders supply limestone to the horizontal ball mills, which wet-grind the limestone to produce a slurry for use in the wet scrubber. The small limestone slurry particle size produces a large surface area for gas contact without excessive power consumption by the ball mill. The limestone slurry product is discharged to a limestone slurry storage tank, and then transferred to smaller feed tanks at the scrubber islands (a common tank for each unit pair) via slurry pumps.

Solids Dewatering

The solids dewatering process proceeds after the solids are precipitated in the absorber tower. The SO_2 reaction with calcium carbonate initially forms calcium sulfite, which is subsequently oxidized to calcium sulfate (gypsum) in the absorber reaction tank. This oxidation process is accomplished by forcing air through spargers that are immersed in the reaction tank slurry inventory. The formation of gypsum crystals in the slurry helps to reduce scaling potential by providing suspended crystal surface for crystal growth and reducing the calcium sulfate saturation level in the slurry. A minimum level of calcium sulfate super-saturation is required to initiate gypsum crystal formation.

A balance between product gypsum and fresh limestone feed in the absorber reaction tank is maintained by removing a 'bleed' stream of slurry from the reaction tank inventory. In the Advatech absorber design, the absorber slurry inventory is operated at a concentration of 30 wt% solids. For the application at Scherer, this bleed stream from each of the four unit absorbers will be pumped to a new settling pond, where the slurry will be allowed to separate into its solid (gypsum) and liquid components. The sludge that settles is typically a 70/30 solids/liquid mixture, and the balance of the water will be reclaimed for re-use in the process.

Of the reclaimed water, a modest portion must typically be discharged, i.e., blown down, to maintain chloride concentration in the absorber below a maximum allowable value (normally 5,000-20,000 ppmw, depending on material selection). The balance of the reclaimed water is used for water supply to the limestone grinding operation and for makeup into the absorber reaction tank.

4.1.2 Lime Spray Drying (LSD) – Dry FGD Process

Refer to the process flow diagrams (SCHR-0-SK-021-305-201, SCHR-0-SK-021-305-202 & SCHR-0-SK-569-304-002) for the dry FGD process in Appendix E. A list of major equipment included in the LSD facility is included in Appendix L.

Overview

The lime spray drying process is a semi-dry FGD process that produces a dry mixture of fly ash and reaction products. The application of the lime spray dryer FGD process to coal-fired boilers is limited to medium and low sulfur fuels, in most cases where a SO_2 removal efficiency of 95% or less is required. The sulfur content of the coals specified for the FGD project at Scherer and the SO_2 removal efficiency required make the LSD process a candidate for the present application.

In the spray drying absorption process, flue gas enters the spray dryer absorption (SDA) module via the gas distribution system which spreads the incoming flue gas symmetrically around the atomizer. The atomizer, which is used to atomize the feed slurry (i.e. a mixture of hydrated lime slurry and recycle solids slurry) into a fine spray and inject it into the flue gas, can be either a rotary design or an air-atomized, two-fluid nozzle design. The finely atomized feed slurry mixes with the flue gas, resulting in the evaporation of water and the removal of the SO_2 via chemical reaction with the slurry.

The quantity of water contained in the atomized spray is precisely controlled so that it completely evaporates in suspension. Absorption of SO_2 takes place primarily as the flue gas is cooled adiabatically by the evaporation of the water contained in the atomized spray. The difference between the temperature of flue gas leaving the SDA and the adiabatic saturation temperature is known as the approach temperature. Reagent stoichiometry, residence time and approach temperature are the primary variables that control the SO_2 removal efficiency in the SDA module.

The primary product of the reaction between the hydrated lime, $Ca(OH)_2$, component of the feed slurry and the SO_2 is hydrated calcium sulfite, according to the following relationship.

- $SO_2 + Ca(OH)_2 \rightarrow CaSO_3 * \frac{1}{2}H_2O + \frac{1}{2}H_2O$

A smaller portion of the sulfur dioxide may also react with oxygen in the flue gas to produce the secondary product of calcium sulfate dihydrate by the following reaction.

- $Ca(OH)_2 + SO_2 + H_2O + \frac{1}{2}O_2 \rightarrow CaSO_4 * 2H_2O$

Sulfur trioxide is also found in the flue gas in small amounts. The sulfur trioxide reaction produces additional calcium sulfate dihydrate by the following.

- $SO_3 + Ca(OH)_2 + H_2O \rightarrow CaSO_4 * 2H_2O$

The majority of the water added to the lime in the initial hydration process is evaporated in the absorber. There are no wastewater streams exiting the absorber. The degree of

reaction depends on the amount of liquid present, the approach to the adiabatic saturation temperature and the residence time for drying.

As the flue gas and feed slurry mixture passes through the SDA module, the spray drying and initial SO_2 removal processes are completed. The SDA module is designed to insure that most of the particulate that can be entrained in the flue gas is carried to the fabric filter dust collector, which is usually of the pulse-jet fabric filter (PJFF) type. The larger, coarser particulate that is not entrained in the flue gas is discharged from the bottom of the SDA module hopper for disposal.

The flue gas and entrained reaction products, un-reacted reagent, and flyash exit the SDA module and then flow into the PJFF, wherein additional SO_2 as well as particulate removal takes place. The reaction products, un-reacted reagent, and flyash collected in the PJFF hoppers is then conveyed by the ash handling system to either the recycle ash storage silo for reuse or the waste ash storage silo for disposal. Upon exiting the PJFF, cleaned flue gas is directed to the booster fans which discharge to the stack.

Spray Dryer Absorber (SDA)

Flue gas is introduced into each SDA module by means of a gas disperser and a roof gas distributor. The purpose of the gas dispersers is to distribute the incoming flue gas symmetrically around the atomizer unit at a velocity and direction appropriate to assure optimum absorption of the acids contained in the flue gas. In the rotary atomizer design, the roof gas disperser has a scroll inlet, which delivers the flue gas to the tapered, annular discharge nozzle positioned around the atomizer. Guide vanes are constructed of abrasion-resistant material and are mounted in the disperser discharge outlet. The purpose of the vanes is to distribute the flow of flue gas uniformly around the atomizer. Careful control of the gas distribution, slurry flow rate and droplet size assures that the droplets are evaporated to dryness prior to contacting the internal walls of the SDA module.

Rotary Atomizer

The rotary atomizer converts the feed slurry to a uniform, finely divided spray of droplets. The rotary atomizer is a precision-made machine designed for high-speed operation and is driven by a vertical, flange-mounted motor specifically designed for the atomizer.

The rotary atomizers are withdrawn from the top of the SDA module for periodic servicing. Gas flow through the SDA module may be maintained when the atomizer is removed for service. A hoist and trolley is typically used to facilitate the change out of the rotary atomizer.

Pulse Jet Fabric Filter

Flue gas with SDA reactant products and boiler fly ash enters the fabric filter inlet plenum and is distributed to each of the individual compartments. The inlet baffle distributes gas and particulate evenly to the filter bags. A portion of the gas is directed downward from the top of the bags minimizing upward velocity and enhancing on-line cleaning. Each filter bag is supported on a wire cage. The bags and cages are

independently suspended from the PJFF tubesheet at the top of each compartment.

Flue gas flow is primarily horizontal and downward through the bags. This flow pattern enhances even gas distribution and minimizes reintrainment when pulsing on line. Collected particulate is cleaned from the bags by pulsing with dried, intermediate pressure compressed air (35 psig) while the compartment remains on line filtering flue gas. The pulse of air dislodges the collected particulate from the bags causing it to fall into the hopper. This material is then conveyed to storage for recycle or disposal. Clean gas exits upward from the filter bags, through the tubesheet and out to the outlet or clean air plenum.

A louver type damper is used to provide inlet isolation for each compartment. The inlet dampers are closed only when a compartment must be isolated for personnel entry when other compartments remain on line. Each compartment also includes poppet type outlet dampers. The outlet dampers must be closed to isolate a compartment for personnel entry, or they can be used for off-line cleaning.

The same type of poppet type damper is also used for system bypass. The poppet design creates a gas and dust tight seal at the common wall between the inlet and outlet plenums. These dampers provide a very reliable metal-to-metal seal without the use of wiper seals or air purge systems. The sealing plate is comprised of several metal discs that provide full contact with a machined metal seat when the damper is closed.

The PJFF control system can be set to operate automatically or manually. The filter bags in each jet assembly are cleaned two rows at a time. Each row of bags has a double diaphragm valve and solenoid which directs a controlled pulse of dry compressed air from the air header to the manifold located above the row of bags.

Lime Preparation

Pebble lime is delivered by rail car, and discharged into an under-track hopper. From the hopper it is transferred by conveyor directly to one of six covered lime storage silos.

The lime preparation system performs the hydration of pebble lime with process water to prepare hydrated lime slurry at approximately 20-25 wt% suspended solids concentration, for spraying into the SDA module. Lime is discharged from each storage silo through a weigh feeder and is fed to an individual lime slaking system, where it is wet-ground and hydrated in a vertical ball mill (or vertimill). The lime slurry product that is discharged from each slaker train is pumped to a common lime slurry storage tank. From this main slurry storage tank, the slurry is transferred to smaller feed tanks at the scrubber areas (a common tank for each unit pair) via slurry pumps.

Lime slurry feed pumps draw suction from the slurry feed tanks and discharge into the lime slurry feed loops. The lime slurry feed loops supply lime slurry to the SDA's for the spray drying process. Constant pump speeds and pipeline velocities are maintained to eliminate settling or caking within the lime slurry feed loop.

Recycle Slurry Preparation

The recycle slurry preparation system provides for mixing of solids collected from the SDA's and PJFF's with process water to prepare recycle slurry at up to 45 w% suspended solids concentration for spraying into the SDA module. The recycle slurry enhances utilization of the lime reagent as well as promoting droplet drying in the SDA modules.

FGD by-product solids being returned to the process are conveyed pneumatically by a (new) ash handling system to the recycle solids silo (one per unit). A bin vent filter captures dust released during silo filling. Recycle material is discharged from the recycle solids silo through a fluidized outlet cone and flows to one of two (2) 100%-capacity recycle slurry preparation trains.

The recycle solids discharged from the storage silo are combined initially with process water in a wetting box. The recycle solids/water mixture that is discharged from the wetting box flows by gravity into the recycle mix tanks where additional water is added. The recycle slurry that is discharged from the recycle mix tank flows via gravity through a vibrating grit screen to remove oversized particles larger than 8 mesh from the recycle slurry. The grit discharged from the grit screen flows via gravity to a disposal bin. Recycle slurry underflow from the vibrating grit screen flows via gravity to the recycle slurry storage tank.

Two, 100%-capacity centrifugal pumps are used for the recycle slurry feed service. Constant pump speeds and pipe line velocities are maintained to eliminate settling or caking within the dedicated recycle slurry supply line to the atomizer head tank.

Waste Solids

Excess solids from the scrubbing process, not used for recycle, are pneumatically conveyed to the by-product storage silos (one each for each pair of units). This material is discharged from each silo through a pin mixer, where it is wetted to control dusting, and is dropped into a dump truck. Large, 100-T trucks are used to haul the material to the on-site landfill.

4.2 Process Operating Characteristics

To quantify the operation of the processes, project-specific combustion calculations, process flow diagrams and mass balances were developed for each of the two alternative FGD processes for each of the two project coals. This information is contained in Appendices D (wet FGD) and E (dry FGD).

At the present conceptual level of engineering, the operation of all four of the Scherer units was treated as identical (as reflected in the Basic Design Basis documents).

The tables in this section were derived from the calculational results in Appendices D & E, and provide the rates of commodity usage/production that enter into the calculation of variable O&M costs.

Table 4-1
Annual SO_2 Mass Balances @ 85% Capacity Factor (tons/yr)

Process	Coal	Input / Unit	Removed / Unit	Discharged / Unit	% SO_2 Removal
Wet	CAPP	79,090	75,920	3,170	96.0
Dry	CAPP	79,090	75,130	3,960	95.0
Wet	PRB	23,570	23,100	470	98.0
Dry	PRB	23,570	21,870	1,700	92.8

The sulfur dioxide removal rates for the wet FGD process are those quoted by Advatech for the specified coals, and represent operation of a single-pass Advatech scrubber vessel.

The sulfur dioxide removal rates for the dry FGD process were estimated by WorleyParsons based on in-house process design experience. For both coals, these dry FGD performance values represent the upper limit of the capabilities of this technology. In the case of operation with PRB coal, the removal rate is limited by the concentration of SO_2 in the outlet flue gas (about 17 ppmv, see the material balance in App. E); that is, the process is not capable of removing SO_2 below this concentration.

Table 4-2
FGD Facility Operating Characteristics at Full Load – Per Unit

FGD Process	Coal	SO_2 Removal (lb/hr)	FGD Reagent Feed (lb/hr)	FGD Byproduct Production (lb/hr)	FGD Makeup Water Usage (gpm)
Wet	CAPP	19,990	41,310	74,850*	1,285
Dry	CAPP	20,150	40,680	78,420	997
Wet	PRB	6,210	12,050	23,570*	1,110
Dry	PRB	5,870	11,500	23,510	1,022

(*) dry basis

The mass feed rates of the two reagents, limestone and lime, are very nearly numerically equal for a given coal, reflecting a much higher calcium usage for the dry process as compared to the wet process (limestone, i.e., calcium carbonate, weighs 2.50 lb per lb of contained calcium, whereas lime, i.e., calcium oxide, weighs 1.40 lb per lb of contained calcium; hence equal mass feed rates of limestone and lime implies a significantly higher

calcium feed rate for the lime case). The wet process is designed with a Ca/S stoichiometric ratio of 1.03, whereas the dry process requires a ratio of about 2.0. This high Ca usage for the dry process is a result of operating this technology at the limit of its capability.

The approximately equal mass rates of byproduct production for both processes, given the differences in Ca feed rates, is a result of differences in the chemical composition of compounds formed in the scrubbing process (i.e., calcium sulfate di-hydrate vs. calcium sulfite), as well as the excess, unreacted lime in the case of dry scrubbing. The chemical composition of the byproducts is described in Section 7.6.

The makeup water requirements, for a given coal, differ between the two processes due to the differences in the flue gas conditions exiting the FGD absorber vessels. The dry technology only requires that the flue gas temperature be reduced to within 35F of the saturation point, whereas the wet technology produces a saturated gas; thus there is less water lost to evaporation in the dry process.

Table 4-3
FGD System Power Consumption at Full Load

FGD Process	Aux. Power / Unit (kW)
Wet	45,000
Dry	27,000

The auxiliary power consumption values listed in Table 4-3 represent order-of –magnitude estimates of time-averaged FGD-based load. The values include, in addition to operation of unit-specific process facilities, power consumption by the booster fans as well as a proportioned share of FGD common facilities. At the present conceptual level, differences in auxiliary power consumption due to operation with the two different design coals were not considered.

4.3 Facility Arrangements

Conceptual-level arrangement drawings were developed for both the wet FGD and dry FGD facilities, including the gas flow train components, the reagent handling and preparation facilities and the by-product storage/disposal areas. These drawings are presented in Appendices F (wet FGD) and G (dry FGD).

These drawings serve to assess overall technical feasibility, to identify key constructability and tie-in issues, and to provide a basis for developing much of the engineering data required for the capital cost estimates.

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4.3.1 Wet FGD

The arrangement of the wet FGD facilities reflects on-going work within SoCo Generation, and also incorporates the physical arrangement of the Advatech 'scrubber island'. The Unit 1 & 2 scrubber islands are grouped around a (new) common, two-flue stack to the south of the power block, with the new booster fans directly behind (to the east) of the existing stack. Adjacent to the new stack is a Unit1&2-common electrical building that houses electrical distribution equipment, the new DCS cabinetry and miscellaneous other facilities.

The Unit 3 & 4 scrubber facilities are arranged similarly, to the north of the power block, but reflect the fact that the larger precipitators on these two units has restricted available space directly behind the boilers and has required that the new booster fans be located adjacent to the scrubber islands.

Four-unit common limestone receiving, storage and preparation facilities are located on the north side of the coal pile area. New rail spurs are provided for limestone delivery, and a radial-stacker conveyor system is used to transfer the limestone to the storage area from the car unloading area. A new access road around the limestone pile is included for emergency delivery of limestone by truck. Limestone is reclaimed from the pile and transferred via conveyor to the limestone preparation area.

The limestone preparation facilities are housed in a building, located adjacent to the limestone storage area. Limestone is received in two day silos, each feeding an individual, horizontal ball mill grinding operation. Limestone slurry product is discharged to an outside storage tank, prior to transfer to (smaller) feed tanks at the scrubber islands.

The new gypsum pond has been located about ½-mile to the north, adjacent to the existing ash pond, and makes use of a naturally-occurring valley. Slurry bleed is pumped out to this pond area, and reclaimed water is pumped back to a storage tank in the limestone preparation area for re-use in the process (primarily limestone grinding).

4.3.2 Dry FGD

In developing conceptual arrangements for the dry FGD facilities, the approach used was to consolidate the locations of the various gas-side components to the maximum extent deemed feasible, because of the need to demolish/reconstruct ductwork during FGD system installation (as described in Section 3.2.2). Although SoCo has subsequently decided not to pursue this arrangement, should a dry FGD system be implemented, it serves as the basis for the current evaluation. The alternative approach of using more spread-out locations for the baghouses, as is currently planned for the mercury control projects, will result in dry FGD project costs that are increased over those estimated in the current study.

The process of developing these arrangements for the dry FGD facility has also resulted in the recognition that implementation of a cost-effective dry scrubber project requires that *the mercury control project and a dry FGD project should be designed as integrated*

projects and constructed in a sequential manner that minimizes reconstruction requirements and tie-in outage durations.

The arrangement developed for the present study 'stacks' the baghouses, that is, the Unit 2 baghouse is stacked on top of the Unit 1 baghouse, and also uses a comparable under/over arrangement for the ductwork. A similar arrangement is used for Units 3 & 4. For Units 1 & 2, all of the major gas-side components (booster fans, spray dryers and baghouses) are located in the open area behind the units, between the stack and the existing access road. To the south are common facilities for these two units: an 'ash' silo, for storage of dry FGD by-product, and a building that houses the ash recycle facilities as well as electrical/DCS equipment.

The Unit 3 & 4 facilities follow a similar grouping, but must be located to the north of the existing stack, again due to the size of the Unit 3 & 4 precipitators, thus requiring more extensive ductwork runs.

Four-unit common lime receiving, storage and preparation facilities are located on the north side of the coal pile area. New rail spurs are provided for pebble lime delivery, and lime is transferred via conveyor from the below-grade unloading hopper to a set of 6 concrete storage silos. Individual lime slaking trains are housed in the bottom of each silo and are fed directly from the silo discharge hoppers. Lime slurry product is discharged to a common storage tank in the silo area, prior to transfer to (smaller) feed tanks in the absorber areas.

The landfill area, for disposal of the dry FGD by-product, has been located about ½-mile to the north, adjacent to the existing ash pond, and makes use of a naturally-occurring valley. A new access road runs out to this disposal area, connecting to existing plant roads, that is used to haul the FGD by-product from the two silos in the scrubber area to the landfill via 100-T trucks.

5. ECONOMIC ANALYSIS

5.1 Approach

The economic performance of each of the two alternative scrubbing technologies was evaluated using a life cycle cost methodology. This type of analysis calculates the net present value of the cash flow associated with a given scenario, or alternative.

For the present study, year-by-year cash flows were developed, covering the period of project construction followed by 20 years of operation for each unit. Costs were developed to describe the two major phases of the commercial life of the FGD facilities.

- Capital costs, for design, construction and commissioning of the facilities.
- Operating & maintenance costs, for materials and labor to operate and maintain the facilities.

The net present value (NPV) calculations were evaluated per the following relationship.

Life Cycle Cost ($) = Sum of Discounted Annual Cash Flow
= Net Present Value [(yr-by-yr capital cash flow) +
(20 yrs of yr-by-yr O&M costs)]

A levelized unit cost was also calculated, which is defined as

Levelized Unit Cost ($/T SO2 Removed) = NPV ($) /
(Tons of SO2 Removed in 20-yr Life),

where the denominator is calculated at the target removal efficiency of 95%.

5.2 O&M Costs

Operating and maintenance (O&M) cost estimates, specific to each technology, were developed on an annual basis. Specific costs were estimated for the following categories of O&M requirements.

- Fixed O&M Costs
  - FGD operating labor (additional new employees)
  - FGD facility maintenance (both labor and material)
  - FGD Administrative and Support Costs
  - Landfill operations
  - Fabric filter bag replacement (dry FGD only)
- Variable O&M Costs
  - FGD reagent supply
  - FGD auxiliary power consumption
  - FGD water consumption
  - SO2 credits

The unit costs used to estimate these components of annual O&M costs were presented in Sec. 3.3.

5.2.1 Fixed

Fixed O&M costs refer to those costs that are independent of the number of hours of plant operation and type of coal fired.

Operating Labor

The number of new plant employees, required to support FGD facility operations, was estimated as shown in the following table for both the wet and dry FGD facilities.

Table 5-1
Estimate of FGD Operating Personnel (Plant-Wide)

[redacted]

The approach taken was to estimate separately, for the dry FGD facility, operating personnel requirements for the by-product landfill operation. Treatment of these costs is described in (the following) Section 5.2.2.

In this table, in addition to developing operating personnel requirements, the average wage rate is developed as a function of the skills mix, using hourly wage rates provided by SoCo for Plant Scherer. The annual all-in cost, used in the O&M estimate, was calculated as follows:

Annual Avg. Cost (all-in) = Hrly Rate ($/hr) * 1.6 * 2080 (hrs/yr),

where the factor of 1.6 was applied to account for indirect costs (i.e., benefits, overhead, G&A).

Operating labor costs were then calculated for each technology from the relationship

Annual Cost = No. of Operating Personnel * Annual Avg. Cost

Maintenance

Maintenance costs for each of the alternative facilities were assessed at 2.7% of the respective FGD project capital costs. This factor of 2.7% is a typical allowance that has evolved in DOE/EPRI technology assessment methodology, and includes labor and material allowances (generally assumed to be a 60/40 split, respectively).

Administrative & Support

Administrative and support costs for each of the alternative facilities were assessed at 0.6% of the respective FGD project capital costs. Again, the 0.6% factor of is a typical allowance that has evolved in DOE/EPRI technology assessment methodology.

Pond / Landfill Operations

FGD by-product sales/disposal costs are traditionally treated as variable costs, since the most common disposition of these materials is to sell the gypsum to a third-party manufacturer or to dispose of the dry by-product in an off-site landfill. In both cases, the associated financial transactions are on a $/T of material handled. However, in the present study, annual costs were applied on a fixed basis per the following procedure.

In the case of the wet FGD facility, no operating personnel requirements were identified for the gypsum pond operation, but an annual cost of [redacted] was assessed for re-stacking of gypsum in the pond area (assumed to be an outside contractor).

For the dry FGD facility, operating personnel are required for hauling the dry by-product out to the landfill area, for stacking and compacting the material in the landfill, and for equipment maintenance and house-keeping. The estimated personnel needed to perform these functions were identified in Table 5-1, and costs were calculated as follows.

Annual Cost = No. of Operating Personnel * Annual Avg. Cost

3 In addition, costs for the mobile equipment and associated spare parts were assessed. The
4 equipment (5 trucks, 1 dozer) were estimated to cost [redacted] and to have a usable lifetime of 10 yrs. Annual cost for spare parts was estimated at 10% of the equipment cost.

PJFF Bag Replacement

The bags in the pulse jet fabric filters used in the dry FGD facility require regular replacement; a 3-year life is typical in this application. Since the same situation occurs with the bags in the mercury removal application, but with a longer bag life (estimated to be 5 years) due to the lower particulate loading, the dry scrubber facility was assessed the incremental bag replacement costs (differential between 3 and 5 years). These costs included material (new bags) and bag installation costs. The bag replacement costs were thus treated in a quasi-fixed manner, in that they were not made dependent on operating hours per year; such treatment was considered justified based on the high capacity factor (85%) for the units.

5.2.2 Variable

Variable O&M costs are those costs that are directly dependent on the number of hours of plant operation. The approach taken to estimate each variable facility cost was to develop a continuous annual rate (i.e., tons/yr, kWh/yr, etc.) based on full-load, continuous operation (8760 hr/yr), and to multiply this value by the annual unit capacity factor to arrive at an equivalent annual rate. The appropriate unit cost (Sec 3.3) was then applied to this rate to arrive at an annual cost. The rates characterizing each of the two FGD technologies were presented in Sec. 4.2.

Reagent

Annual Reagent Costs = 4*Consumption Rate (#/hr / unit) / 2000 (#/T) * Unit Cost ($/T) * 8760*Capacity Factor (hr/yr)

Aux Power / Water Consumption

Here, the cost relationships are straight forward.

Annual Aux Power Costs = 4*Consumption Rate (kW/unit) / 1000 (kW/MW) * Unit Cost ($/MWh) * 8760*Capacity Factor (hr/yr)

Annual Makeup Water Costs = 4*Consumption Rate (gpm/unit) / 60 (min/hr) / 10^6 * Unit Cost ($/Mmgal) * 8760*Capacity Factor (hr/yr)

SO_2 Credits

As identified in Table 4-1, the various technology/fuel combinations have different sulfur dioxide removal efficiencies. To evaluate each of these on an equivalent performance basis, costs/credits were assessed for each relative to the target removal efficiency of

95%. That is, for alternatives where the removal efficiency is below 95%, costs for SO_2 allowances were assessed based on tons/yr of SO_2 emitted that exceed the 95% removal rate. In a similarly fashion, a credit was given to a particular alternative for tons/yr of SO_2 removed that exceed the 95% removal rate.

Annual SO_2 Allowance Cost = 4 * SO_2 Input/Unit (T/yr) *
(0.95 – Removal Efficiency/100) * SO_2 Allowance Rate ($/T)

5.2.3 O&M Results

The annual O&M costs vary from year to year, due to varying year-by-year unit costs and/or due to differing treatment. The complete build-up of these costs, through the full 20 years of operating life for each unit, is contained in the spreadsheets in Appendices H (wet FGD) and I (dry FGD).

Here, for illustrative purposes, the results of the analysis are described just for the year 2015, which is the first full year that the FGD facilities on all four units are in service. The following table summarizes the results for operation with bituminous (CAPP) coal, which was specified as the baseline fuel for the economic comparison of the two alternatives technologies.

Table 5-2
Annual Plant-Wide O&M Costs for Yr. 2015
CAPP Coal

A B C

[redacted]

Although there are modest differences between the two technologies in most cost categories, the key result is the significantly greater cost of lime for the dry FGD technology than the limestone for the wet FGD technology. This difference results in an annual O&M cost for dry FGD that is about twice that for wet FGD.

Comparable results for PRB coal are presented in the following Table 5-3. Here, the incremental total O&M cost for dry FGD in comparison to wet FGD is less pronounced but still significant.

Table 5-3
Annual Plant-Wide O&M Costs for Yr. 2015
PRB Coal

A B C

[redacted]

5.3 Capital Costs

See Appendix J for the basis of the capital cost estimates. See Appendix K for the capital cost estimates for both the wet and dry FGD systems. The associated major equipment lists for each technology are contained in Appendix L.

Table 5-4
Project Capital Cost Estimate Summaries

[redacted]

For application to the life cycle cost analysis, the total capital cost for each of the two alternatives was spread over the construction period to provide annual capital cost expenditures. The procedure was to first divide the project total into the sub-totals for units 0 through 4 (0 = common), and to then spread each unit sub-total into yearly expenditures; the distribution for these yr-by-yr spreads was based on WP's experience with another 4-unit FGD project. For each unit, the yearly cash flows were distributed over the unit-specific project dates identified in the preliminary project schedule (Section 6), and summarized in the following table.

Table 5-5
Key Project Construction Dates

[redacted]

Design and construction of both the wet and dry facilities were assumed to follow this same schedule.

In addition to the accounting for the project engineering and construction costs, as described above, both alternatives were assessed costs for lost generation during the tie-in outage for unit (using the daily costs listed in Table 3-1). Based on the constructability evaluation (Section 7.10), a tie-in outage duration of 2.5 weeks was used for each wet FGD unit, and 10 weeks for each dry FGD unit.

5.4 Life Cycle Cost Results

5.4.1 Baseline

The complete buildup of year-by-year costs, over the period of evaluation, for the wet and dry FGD alternatives are contained in the spreadsheet printouts in Appendices H and I, respectively. The resulting net present value costs for the baseline CAPP coal are shown in the following table.

Table 5-6
Life Cycle Cost Results
CAPP Coal

A	B	C
[redacted]		

For the baseline CAPP fuel, the dry FGD facility is found to have a life cycle cost about 63 % greater than the comparable cost for a wet FGD system. The dry FGD technology is burdened by 25% higher capital costs, as well as 125% higher operating costs (primarily due to lime purchase). This difference in operating costs is the most significant differentiator.

5.4.2 Parametric Comparisons

The results of the corresponding life cycle cost analysis for the two technologies with the alternate project coal, PRB, are listed in Table 5-7.

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Table 5-7
Life Cycle Cost Results
PRB Coal

[redacted]

In this case, the operating costs are much reduced compared to the CAPP coal results, and subsequently the difference in life cycle costs is much less pronounced, but still results in a dry FGD levelized unit cost that is 43% greater than for the wet FGD.

The effect of assessing costs/benefits for SO_2 allowances (as a method of compensating for differences in SO_2 removal efficiencies between the different coal/technology combinations) was quantified by calculating the baseline life cycle cost with this cost account deleted. The comparison of this variation is shown in the following table, and demonstrates that the effect is minor and that it does not have a significant impact on the comparison of the two technologies.

Table 5-8
Life Cycle Cost Results – Without SO2 Allowances
CAPP Coal

[redacted]

The impact of uncertainty in the project capital costs was quantified by running the baseline life cycle analysis with the dry FGD capital costs varied by +/- 20%, while holding the wet FGD capital costs constant. The results are listed in Table 5-9.

Table 5-9

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Life Cycle Cost Results – Capital Cost Variation
CAPP Coal

A B C D E

[redacted]

These results indicate that even a significant variation in capital cost does not change the primary conclusion that the wet FGD technology has a significantly lower life cycle cost than the corresponding dry technology.

6. MILESTONE PROJECT SCHEDULES

The conceptual Project Milestone Schedules are illustrated in Appendix M. One schedule is prepared for each of the following.

- Wet FGD, Units 3 and 4
- Wet FGD, Units 1 and 2
- Dry FGD, Units 3 and 4
- Dry FGD, Units 1 and 2

The schedules illustrate the flow of preliminary and detailed engineering, procurement activities, and construction activities for both the wet and dry scrubbers. The dates for outages and in-service dates that were provided by Southern Company were followed and are determined to allow a realistic construction schedule. WorleyParsons has compared the Southern Company draft schedule to our previous milestone schedules and find that the durations provided are consistent with our previous experience.

Generally, the level of effort for design, procurement and construction and nearly the same between the scope of the Wet and Dry FGD systems, so we have left the schedules very similar in overall duration. We have, however, reduced the overall construction schedule for Units 4 and 1 from 30 months to 27 months but kept the in-service dates for both the wet and dry scrubbers. This is primarily due to the first units carrying the responsibility of construction and preparing the Common equipment, such as the reagent unloading and preparation systems, and the new chimneys for the Wet FGD systems. For these reasons, Units 4 and 1 should have a slightly shorter construction schedule than Units 3 and 2.

Note that all procurement activities for all four units will begin with the first unit. This will allow continuity of equipment and spares by purchasing all equipment at one time for the four units. The vender engineering and drawing reviews will be completed for all four units, but shipment will be scheduled as appropriate for each unit.

The major difference in the schedules is the outage duration for the wet versus the dry FGD systems. Due to the demolition work of PJFF ductwork and the complexity of the construction plan, the dry FGD System outage will require a minimum of 10 weeks. Note that the complexity of the dry FGD Construction Plan could require the outage schedule to grow to 12 to 14 weeks. The duration will be determined after careful evaluation of construction activities and sequence in the preliminary and detailed engineering phases. The wet FGD system outage will only require 2 weeks, due to the relatively straight-forward nature of the construction plan.

Note that the major complicating factor for the dry FGD system is the reconfiguration and removal of PJFF ductwork that was originally installed for Mercury Control. With the installation of the dry FGD system, the PJFF ductwork must now be re-configured to position the PJFF downstream of the dry FGD system to catch the spray dryer reaction products for disposal. For the Mercury Removal system, the PJFF was directly downstream of the ESP to allow the flyash to be collected in the ESP rather than contaminated by mercury solids in the PJFF. This maximizes the amount of uncontaminated flyash that Southern Company can collect and sell. However, the ductwork reconfiguration will be a significant effort. A majority of the previous ductwork will be removed prior to installation of the ductwork to all spray dryers. The construction area will be very congested and will be a major reason for the 10 week minimum outage duration.

7. ENGINEERING EVALUATION OF BALANCE-OF-PLANT ISSUES

7.1 ID and Booster Fans

Both the dry and the wet FGD facilities will introduce substantial additional draft loss into the flue gas flow train, requiring upgrade of the static pressure (SP) capability of the flue gas draft system. Only minor changes, at most, to the gas flow *rate* will occur.

The present set of 4x25% centrifugal ID fans on each unit provide draft for the flue gas flow through the existing flow train, as depicted in the diagram SCHR-0-253-305 -001 (Appendix C). In the first phase of the up-coming AQC projects, i.e., the mercury removal project, it is planned that these existing ID fans will be upgraded to give them sufficient additional head capability to provide draft for both AQC phases that will precede the FGD facility installation (the mercury removal facility and the selective catalytic reduction (SCR) facility), while maintaining draft for the existing flow train. This flow configuration is depicted in the diagram SCHR-0-253-305 -003 (Appendix C).

Both the wet and dry FGD facilities will tie in their supply ductwork at the discharge of the existing ID fans. Since an (approximate) null draft will exist at this point, it will be necessary to provide additional draft capability for the FGD flow train; it is planned that

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this requirement will be met by addition of a pair of axial flow booster fans for each unit as part of the FGD installation scope.

The functional flow arrangements for the booster fans are shown in diagrams SCHR -0-253-305 -004 and -005 (Appendix C) for the wet and dry technologies, respectively. The (assumed) null draft condition at the ID fans discharge establishes the starting point for estimating the head capability of the booster fans for the present study.

Note: The flow/SP values listed in this section for the booster fans were developed early in the study to serve as a basis for a vendor budgetary quotation. As such, there are modest differences in these values when compared to the corresponding values in the final process material balances (Appendices D & E).

7.1.1 Wet FGD

The booster fans for the wet FGD installation will operate in a configuration where the fans will have a slightly negative suction pressure (resulting from the draft loss between the tie-in point and the fan inlet), and discharge into a positive-pressure flow train through the scrubber island, connecting ductwork and stack.

The head requirements for the booster fans, operating to support this wet FGD configuration, were estimated as indicated in the following table. Here, the 1st component was estimated based on engineering experience, and the 2nd component is specified in the Basic Design Basis document.

Table 7-1
Draft Loss for Booster Fans – Wet FGD

Component	MCR Draft Loss (" wg)
Booster Fans Supply & Discharge Ductwork Loss	3.0
Scrubber Island Inlet to Stack Discharge	12.0
Total	15.0

The gas flow rate was estimated at 5,820,000 lb/hr per fan, or 1,944,000 (A)CFM. The corresponding performance requirements for the booster fans were specified as follows.

Table 7-2
Booster Fan Performance Specifications – Wet FGD

Operating Condition	Flow, Fan (CFM)	Static Pressure, SP (in wg)	Temperature (F)	Inlet Density (lb/ft³)
Boiler MCR	1,944,000	15.0	345	0.0499
Test Block	2,236,000	19.8	345	0.0499

A budgetary quotation from Howden/Buffalo for the fans specified the following design parameters.

Table 7-3
Booster Fan Design Parameters – Wet FGD

Parameter	Value
Impeller Diameter	176.4"
Speed	720 rpm
No. Stages / Blades	1 / 20
Motor Rating	12,000 hp
Brake hp (MCR)	8,234
Brake hp (Test Block)	10,911

7.1.2 Dry FGD

The booster fans for the dry FGD installation will operate in a configuration where the fans will pull flue gas, under negative pressure, from the ID fans discharge through the spray dryer modules, the baghouses and connecting ductwork to the fans suction; the fans will discharge at slightly positive pressure into connecting ductwork and the existing stack.

The head requirements for the booster fans in the dry FGD facility were estimated as follows.

Table 7-4
Draft Loss for Booster Fans – Dry FGD

Component	MCR Draft Loss ("wg)
ID Fans to LSD's Dkwk	1.0
Lime Spray Dryers (LSD's)	2.0
Baghouses	5.0
Booster Fan Supply/Discharge Dkwk	3.0
Total	10.0

The gas flow was estimated at 5,862,000 lb/hr per fan, or 1,702,000 (A)CFM. Thus fan performance criteria were established as follows.

Table 7-5
Booster Fan Performance Specifications – Dry FGD

Operating Condition	Flow / Fan (CFM)	Static Pressure, SP (in wg)	Temperature (F)	Inlet Density (lb/ft³)
Boiler MCR	1,702,000	10.0	166	0.0574
Test Block	1,957,000	13.2	166	0.0574

A budgetary quotation for fans meeting these specifications was solicited from Howden/Buffalo. Their response offered fans with the following characteristics.

Table 7-6
Booster Fan Design Parameters – Dry FGD

Parameter	Value
Impeller Diameter	196.9"
Speed	590 rpm
No. Stages / Blades	1 / 20
Motor Rating	6,500 hp
Brake hp (MCR)	4,716
Brake hp (Test Block)	5,842

7.2 Pulse Jet Fabric Filters

7.2.1 Wet FGD

An activated carbon injection system and PJFF for mercury control will be installed upstream of the limestone wet FGD system. In this configuration, there will be two (2) 12-compartment PJFF's installed on each unit. This equipment will be installed downstream of the existing ESPs which will stay in service. With the ESPs in service, the PJFFs will operate at higher air to cloth ratios in a TOXECON™ arrangement. Under the Basic Design Basis criteria, these PJFFs will operate at 5.48 fpm (gross) and 5.98 fpm (net-2) at maximum conditions. These are typical air to cloth ratios for a TOXECON™ installation. At higher air to cloth ratios, the PJFF becomes very sensitive to the particulate loadings from flyash carryover and from the particle size of the activated carbon.

The design parameters are shown in column A in the table below. One (1), two(2)-casing, 24-compartment, Size 2830 Model 315 VIP Pulse Jet Type Fabric Filter from Wheelabrator (WAPC) will be supplied for each unit.

Table 7-7
Mercury Control PJFF Design Parameters

Item	A	B
	With Wet FGD	With Dry FGD
Casings per Unit	2	3
Number of Compartments in each Casing	2@12	2@12, 1@6
Bag Array (Per Compartment):		
Bag Quantity (Width Direction)	28	28
Bag Quantity (Depth Direction)	30	30
Bag Length (ft.)	26.25	26.25
Bag Diameter (in.)	5 (nominal)	5 (nominal)
Cloth Area per Compartment (ft^2)	28,698	28,698
Total Cloth Area (ft^2)	688,750	860,938
Volumetric Flow rate, acfm	3,774,160	3,372,974
Gas to Cloth Ratios (At Max. Conditions):		
All Compartments on-line	5.48	3.92
Two Compartments off-line	5.98	4.20

7.2.2 Dry FGD

An activated carbon injection system for mercury control will be installed upstream of a lime dry FGD system. In this configuration, the PJFF is installed downstream of the dry FGD system. The design parameters are shown in column B in the Table 7-7, above. With the addition of the dry FGD in front of the PJFFs, everything changes. With the current PJFF size, the air to cloth ratios would be 4.76 gross and 5.20 net-1. These are much too high for a dry FGD particulate removal application due to the high solids

loading generated by the DFGD. *For conceptual design purposes, we have assumed the addition of a 5th row of six (6) PJFF modules in parallel with the existing casings for each unit.* These compartments would be the same size (840 bags) as the current WAPC design. Under these conditions, the modified PJFF system with the additional 6 compartments will operate at air to cloth ratios of 3.92 fpm (gross) and 4.120 fpm (net-2). This configuration represents an acceptable design for a PJFF with dry FGD and activated carbon injection.

7.3 Flyash Handling

7.3.1 Wet FGD

The wet FGD facility is configured so that it will have no direct impact on the existing flyash handling operation, or material handling from the baghouse hoppers in the up-coming mercury removal project.

Following installation of a wet FGD facility, it is planned that the existing precipitators will remain in service, and that collection and sale of the flyash will continue.

7.3.2 Dry FGD

The dry FGD facility is configured so that it will have no direct impact on the existing flyash handling operation. Following installation of a dry FGD facility, it is planned that the existing precipitators will remain in service, and that collection and sale of the flyash will continue.

However, the dry FGD facility will require modification/replacement of the pneumatic ash handling system that serves the hoppers of the baghouses installed for the (prior) mercury removal project. Since the volume of material handled, in changing from mercury removal to dry FGD service, will increase by at least an order of magnitude, it was assumed that the pneumatic handling system would be replaced.

The baghouses, when functioning as components of the dry FGD facility, will collect a mixture of particulate composed of FGD byproduct waste (calcium/sulfur compounds), unreacted lime, reacted/unreacted carbon, inerts and (minor amounts of) fly ash.

Refer to diagram SCHR-0-021-305-201 (Appendix E). The waste solids collected in the spray dryer and baghouse hoppers will be pneumatically conveyed to either the solids recycle silos (one per unit, located in the recycle/electrical buildings) or to the ash storage silos (one for Units 1&2, one for Units 3&4). This new ash handling system will include hopper feeders, two pressure blower skids, two ash storage silos, truck loading mixers and feeders (one set per silo), and the necessary piping and valves to transport the ash to the desired locations.

7.4 Bulk Material Handling

7.4.1 Wet FGD

The limestone handling system will accept delivery of limestone primarily by rail. Limestone from the rail unloading hoppers will be transported to a storage pile formed by means of a radial stacker. The storage pile will be uncovered. Two hoppers with belt feeders in a tunnel below the limestone pile and associated conveyor system will gravity reclaim the limestone and transport it to two limestone silos.

As shown on Southern Company's own plant concept drawing for the wet FGD option, a radial stacker is provided for the stacking of the limestone storage pile. On a similar project, WorleyParsons has used a fixed stacking conveyor with a telescopic chute for this type of application. Given the capacity of the storage pile needed, the fixed stacking conveyor with telescopic chute offers advantages over the radial stacker. These include less capital, operating and maintenance costs. This issue can be discussed further in Phase I – Preliminary Engineering of the project.

Given the 30 day storage capacity of the storage pile, no equipment redundancy has been provided for the flow path from railcar unloading to storage pile. While the reliability of this equipment is high, any downtime must be minimized so as not delay the unloading of railcars and cause any possible demurrage.

One belt feeder, conveyor and radial stacker will be used to unload limestone railcars and transport the limestone to the top of the storage pile. Two belt feeders, each supplying one of two redundant reclaim conveyors that convey limestone to the top of the silos, will be provided. A dust suppression system will be provided at the unloading hoppers. Dust collectors will be provided to serve the two silos.

Table 7-8
Limestone Material Handling Design Parameters

Limestone Physical Properties	
Size:	¾" x 0
Moisture Content:	10 % Max.
Bulk Density Range:	80 – 120 lb/ft^3
Bulk Density for Volumetric Sizing of Conveyor Chutes, etc.:	80 lb/ft^3
Bulk Density for Volumetric Sizing of Silos:	85 lb/ft^3
Bulk Density for Volumetric Sizing of Storage Piles:	95 lb/ft^3
Bulk Density for Structural Design:	120 lb/ft^3
Angle of Repose:	38°
Limestone Use Requirement	
Design Basis:	1.5 % sulfur coal (Appalachian) at 100% plant

	load (4 units operating)
Hourly Requirement:	81.8 tons/hr
Daily Requirement:	1,962± tons/day
Limestone Unloading Requirements	
Primary method is rail receiving.	
Approximate Maximum Weekly Delivery Requirement:	13,750 tons
Train Sizes (Estimated):	120 car unit trains; will split into 30 car units for unloading
Rail Car Capacity:	100 tons
Weekly Rail Car Unloading Requirement:	138 cars (approximate)
Rail Car Maximum Length:	53' – 1" c. to c.
Rail Car Type:	Open, bottom dump cars with multiple discharge doors, manually operated from one or both sides of car
Limestone Unloading Pit	
Unloading Pit Length:	One rail car length
Minimum Hopper Length:	≥ 32' (based on maximum bottom opening of N.S. limestone service rail cars)
Minimum Hopper Capacity:	125 tons (125% of one rail car)
Maximum (Design) Unloading Capacity:	20 cars/hr
Receiving and Stacking System	
Limestone Belt Feeder #1 and Limestone Conveyor #2 Capacity:	2,200 tph
Radial Stacker	Slewing, variable height style; 2200 tph
Limestone Stockpile	
Shape:	Kidney Shaped with extension
Stacking Method:	Radial Stacker
Capacity: (Total requirement of kidney shaped pile plus extension [live and dead storage] for 30 days)	60,000 tons
Reclaim System Design Basis	
Stockpile reclaim shall utilize live gravity reclaim with remotely controlled feeders and conveyors to the greatest extent possible without requiring mobile equipment support. System	

shall use two redundant reclaim systems to deliver to the limestone silos.	
Available Live Capacity in Stacked Pile Filled to Maximum Height:	8,000 tons – 4 days (estimated)
Available Capacity in Stacked Kidney Shapeed Pile Filled to Maximum Height: Note: Not all of this storage is reclaimable without the use of mobile unloading equipment.	24,000 tons – 12 days (estimated)
Required Capacity of Reclaim and Distribution Conveyors:	100% of daily requirement delivered within 4 hr operating time = 480 tph
Design Capacities	
Belt Feeders:	480 tph
Conveyors:	480 tph
Limestone Silos Design Basis	
Quantity:	Two (2)
Capacity:	675 ton each (8 hours at daily rate)
Dust and Emission Control	
Unloading Pit:	Water/surfactant suppression system at hoppers
Silo Loading:	One dust collector at top of each silo
Conveyors:	Outdoor sections of conveyors have continuous hood covers

7.4.2 Dry FGD

The lime handling system will accept delivery of pebble lime primarily by rail from covered railcars. Lime from the two rail unloading hoppers will be transported by belt feeder and belt conveyor directly to six concrete silos. The lime will be distributed among the silos by a horizontal belt conveyor and traveling tripper atop the silos. Dust collectors will be provided to serve the six silos.

Given the 30 day storage capacity of the storage silos, no equipment redundancy has been provided for the flow path from railcar unloading to storage silo. While the reliability of this equipment is high, any downtime must be minimized so as not delay the unloading of railcars and cause any possible demurrage.

A conventional sloped belt conveyor is provided from the railcar unloading to the top of the storage silos. Based on this estimated height of the storage silos, this conveyor elevates the lime over 265 ft. from underground feeder discharge to the top of the silos. A potential savings may be realized based on the use of a High Angle Conveyor (HAC) in place of this conventional belt conveyor. This issue can be discussed further in Phase I – Preliminary Engineering of the project.

Table 7-9
Lime Material Handling Design Parameters

Lime Physical Properties	
Type:	Pebble
Size:	¾" x 0
Bulk Density Range:	50 – 70 lb/ft^3
Bulk Density for Volumetric Sizing of Conveyor Chutes, etc.:	50 lb/ft^3
Bulk Density for Volumetric Sizing of Silos:	60 lb/ft^3
Bulk Density for Structural Design:	70 lb/ft^3
Angle of Repose:	38°
Lime Use Requirement	
Design Basis:	1.5 % sulfur coal (Appalachian) at 100% plant load (4 units operating)
Hourly Requirement:	83.7 tons/hr
Daily Requirement:	2,009± tons/day
Lime Unloading Requirements	
Primary method is rail receiving.	
Approximate Maximum Weekly Delivery Requirement:	14,060 tons
Train Sizes (Estimated):	120 car unit trains; will split into 30 car units for unloading
Rail Car Capacity:	100 tons
Weekly Rail Car Unloading Requirement:	141 cars (approximate)
Rail Car Maximum Length:	42' – 0" c. to c.
Rail Car Type:	Covered, bottom dump cars with multiple discharge doors, manually operated from one or both sides of car
Lime Unloading Pit	
Unloading Pit Length:	One rail car length
Minimum Hopper Capacity:	125 tons (125% of one rail car)
Maximum (Design) Unloading Capacity:	20 cars/hr
Receiving System	
Lime Belt Feeder #1 and Lime Conveyor #2	2,200 tph

Capacity:	
Silo Conveyor #3 and Tripper Capacity:	2,200 tph
Lime Silos Design Basis:	
Quantity:	Six (6)
Capacity:	10,000 ton each for a total of 60,000 tons – Approx. 30 days storage
Dust and Emission Control	
Unloading Pit:	Dust collection system at hoppers and feeder discharge
Silo Loading:	One dust collector at top of each silo
Conveyors:	Outdoor sections of conveyors have continuous hood covers

7.5 Wastewater Treatment

7.5.1 Wet FGD

The wet FGD process is configured such that slurry bleed from the absorbers is pumped to a (new) settling pond where separation of the solid material (gypsum) from the water occurs. The water that is reclaimed from this process is recycled back into the scrubbing process.

This water recycle configuration concentrates dissolved solids, notably chlorides and heavy metals, in the process water streams. The prelimary FGD water balance for the CAPP coal indicates that it will be necessary to blow down a portion (~ 8%) of the recycle water to maintain the chloride concentration within the design value of 20,000 ppmw.

The estimate of blow-down quantity from the four units is on the order of 100 gpm (~ 0.15 Mgd); this liquid is characterized as a flow containing high chloride and heavy metals concentrations. Discharge of this flow to one of the ponds or basins on site could require a revision of NPDES permit to include new monitoring requirements and/or effluent limits, depending on the quality and volume of the discharge and any additional wastewater treatment systems the plant may install.

It is recommended that a comprehensive and thorough evaluation of the need for treatment of this blowdown be conducted.

In the present study, *no* costs were included for wastewater treatment from the wet FGD facility. If a wastewater treatment facility were required, based on recent WorleyParsons project experience the costs would likely be in the range of [redacted]

7.5.2 Dry FGD

Installation of a dry FGD facility will not require a wastewater treatment facility. However, it will be necessary to dispose of an estimated 25-30K gpd of sump discharge water (due to wash-downs). It is assumed that sump discharge water can be disposed of in the ash pond, but may require a revision to the NPDES permit.

Waste water generated by the proposed dry FGD facility is expected to amount to about 10-15K gpd in the lime slaking and recycle operations due to periodic wash-downs. Waste water that would be generated during periodic wash-downs at the ash storage silos is expected to be about another 15K gpd. Waste water would be collected in the floor sumps located in the various process areas, and discharged to the ash pond or other on-site wastewater basin

7.6 FGD By-Product Storage/Disposal

7.6.1 Wet FGD

The by-product resulting from the wet LSFO process is primarily gypsum ($CaSO_4$-$2H_2O$), with minor components consisting of inerts, unreacted limestone and flyash.

Table 7-10
FGD By-product Characteristics – Limestone Forced Oxidation
CAPP Coal

MCR Rate	(T/hr)
Production (4 Units)	149.7 (dry basis)
Composition	**(Wt %)**
$CaSO_4$-$2H_2O$	81
Moisture	–
$CaSO_3$-$1/2H_2O$	<1
$CaCO_3$	2
$MgCO_3$	<1
Alkali Inerts	13
Flyash	2

This material, commonly known as synthetic gypsum, has substantial commercial application for wallboard manufacture. In the present study, the wet FGD process has been configured to deposit the gypsum slurry (bled from the absorbers) in a new settling pond, as described in Section 7.9.1, and to then let the gypsum separate and accumulate in the pond. It is planned to then regularly use a drag-line excavator to stack the settled gypsum into a long term storage arrangement. This procedure thus permits the options of

either reclaiming the gypsum some time in the future for commercial sale, or ultimately closing the stack as a permanent land fill.

7.6.2 Dry FGD

The by-product produced by the dry LSD process consists of reaction products, excess hydrated lime, inerts, flyash, and moisture. The reaction products are calcium sulfite, gypsum, and calcium chloride. Based on using a lime reagent with 90% activity (CaO), the byproduct production rate and composition are as listed in the following table.

Table 7-11
FGD By-product Characteristics – Lime Spray Drying
CAPP Coal

MCR Rate (4 Units)	(T/hr)
Recycle	220.8
Disposal	156.8
Total Production	377.6
Composition	**(Wt %)**
$Ca(OH)_2$	15
$CaSO_3$-1/2H_2O	80
$CaSO_4$-2H_2O	incl. above
$CaCl_2$-2H_2O	incl. above
$CaCO_3$	incl. above
Inerts, Carbon	incl. above
Flyash	3
Moisture	2

At present, there are only very limited commercial uses for this dry FGD by-product material. In almost all instances, the byproduct material from operating LSD facilities is disposed of in a landfill. In the present study, it is assumed that the material will be hauled to a new on-site landfill, as described in Section 7.9.2.

7.7 Control System

Plant Scherer requires an expansion, for each unit, of the existing Foxboro 1A Series Distributed Control System (DCS) for control of the new flue gas desulfurization (FGD) system. The expansion of the existing Foxboro 1A Series DCS will allow connection of the new controls for the FGD system.

The new DCS equipment must meet guidelines in response to the requirements of the North America Energy Reliability Council (NERC). Due to the criticality of the DCS to Unit Operation, means of digital and physical security will need to be provided. The use of wireless devices will not be permitted.

The design requirement is to expand the DCS for control of the new FGD system equipment. The existing DCS equipment will be retained and new FGD DCS equipment controls will be provided as a separate node on the existing data highway.

All control and monitoring functions for equipment and control devices associated with either the wet or dry FGD system will be controlled by the DCS. Selected equipment may be locally controlled. The limestone handling equipment and reagent preparation or dry FGD baghouses will each be controlled by a stand-alone Programmable Logic Controller (PLC). All interface signals required between the PLC's and the DCS will be hardwired.

All control and monitoring functions will be available from the main control room utilizing the existing operator work stations. No new operator work stations are required for the expansion. Signals required for interface between the expanded FGD DCS and the existing plant DCS will be hardwired. It is assumed that any new control cabinets will be located in the FGD electrical equipment buildings.

New graphics will be configured for the FGD equipment using the current plant convention for symbols, colors and initiating operation of equipment/devices. This approach will ensure common presentation of plant displays throughout the control system. The new graphics will provide all the functionality of the existing graphic design.

There are no control issues specific to either the wet or dry technology. It is recommended that the control logic for the booster fans be added to the existing Combustion Control process. The ID Fan logic should remain as is; however, the booster fan control and Main Fuel Trip (MFT) scenarios should be investigated in more detail.

7.8 Electrical Distribution

7.8.1 Wet FGD

The wet FGD system for Unit 1 will be fed from a 50/66/83 MVA, three winding transformer tapped off the generator ISO phase bus. See drawing SCHR-0-SK-625-206-001 (Appendix N). Each winding will feed a 13.8 KV switchgear. The 13.8 KV switchgear will provide power to the 12,000 hp booster fans. Another feed will supply power to a 13/17/25 MVA, two winding transformer for the FGD electrical distribution system.

The FGD electrical distribution system will use 4.16 KV switchgear as the source of power for large and medium voltage motors and the unit substations. The unit substations are the source of power for the motor control centers and the larger low voltage motors. The motor control centers supply power to the smaller low voltage motors, lighting, and other miscellaneous loads.

This same arrangement will be used for Unit 2.

Start-up power for the FGD facilities and booster fans, for both Units 1 & 2, will come from the 115 KV switchyard. The 115 KV supply will be transformed to 13.8 KV through a three winding transformer rated 50/66/83 MVA. Each of the 13.8 KV windings will supply one of the 13.8 KV switchgear in Units 1 & 2.

Units 3 & 4 will have an electrical distribution arrangement similar to Units 1 & 2.

7.8.2 Dry FGD

The electrical distribution for the dry FGD facility is similar to that for the wet FGD facility. The primary source is from a three winding transformer rated 30/40/50 MVA. See drawing SCHR-0-SK-625-206-002 (Appendix N). Each winding supplies a 6.9 KV switchgear. This switchgear supplies power to the 6500 hp booster fans and, unlike the wet system, the medium voltage motor and unit substations are fed from this switchgear.

The remainder of the electrical distribution is similar to the wet system. Like the wet system, start-up power will come from the 115 KV switchgear through a three winding transformer. The transformer will be rated 30/40/50 MVA. As in the wet system, each winding will supply a 6.9 KV switchgear in Units 1 & 2.

Units 3 & 4 will have an electrical distribution arrangement similar to Units 1 & 2.

7.8.3 General

It is noted that confirmatory studies on these conceptual arrangements are needed to assure booster fan starting ability which will finalize transformer size rating, voltage level and transformer impedance. Along with motor starting, short circuit withstand must be investigated. These studies will be conducted when further data is available and preliminary design is underway.

7.9 Civil

7.9.1 Wet FGD

Gypsum slurry will be pumped to a proposed settling pond for storage or final disposal. The decanted water will be returned to the FGD process for reuse. The pond will be located east of the existing ash pond and will be formed by constructing an earthen embankment dam in a natural valley (see dwg. No. SCHR-0-111-002-101, App. F). The pond and its related facilities will cover approximately 185 acres. The area at the pond water line will be approximately 150 acres. The storage volume required for a 20-year life is approximately 12,000 to 14,000 acre-feet of gypsum.

The pond will have a maximum depth of about 60 feet and when the pond storage capacity is reached, the gypsum will be "stacked" on the previously deposited gypsum by a drag line excavator, as described in the EPRI report No. TR-104731. The drag line will construct a new pond embankment with gypsum. When the embankment is completed, the gypsum sluice discharge pipes will be relocated to the newly formed, elevated pond. Additional stacking operations will be used to accommodate the total gypsum volume. It has been assumed that the pond will require a liner to prevent infiltration of contaminants

into the surrounding soil. A single layer of geosynthetic clay liner (GCL) was used for the cost estimate. Closure of the pond/stack was not included. Final closure, if implemented, may require a liner "cap" over the gypsum.

7.9.2 Dry FGD

The dry FGD by-product will be trucked to a proposed landfill site for final disposal. The landfill will be located east of the existing ash pond and will be formed by the valley-fill method in a natural valley (see dwg. No. SCHR-0-111-002-201, App. G). The solid waste material will be placed, spread and compacted with earthmoving equipment. The landfill and its related facilities will cover approximately 185 acres. The area at the waste material limits will be approximately 150 acres. The storage volume required for a 20-year life is approximately 12,000 to 14,000 acre-feet.

The landfill will have an average final depth of about 80 to 95 feet when the storage capacity is reached. It has been assumed that the landfill will require a liner to prevent infiltration of contaminants into the surrounding soil. A single layer of geosynthetic clay liner (GCL) was used for the cost estimate. Closure of the landfill was not included. Final closure may require a liner "cap" over the waste material.

7.10 Constructability Evaluation

7.10.1 Wet FGD

Units 3 & 4

The wet FGD facility layout for these two units allows for sufficient construction access to both units. With the current pipe bridge location, the ideal layout for construction would be to place the Unit 3 scrubber island to the east. This would eliminate working around live utilities during construction of Unit 4 and create a safer working environment. The electrical building placement is critical to keep wire runs short, and at the same time not interfere with access to the construction site. The stack erection would be critical path due to an exclusion zone required to erect the stack prior to beginning scrubber island erection. If the schedule is critical and a 50' exclusion zone could be agreed upon with the stack erector, the scrubber islands could be arranged outside of this zone. This arrangement would allow for concurrent installation, but would increase the cost of the fiberglass duct from the scrubber outlet to the stack. The liner installation could continue concurrently with the scrubber island erection; for safety reasons both liners should be installed before operation of the first unit. Most if not all of this ductwork could be modularized or ground fabricated which would reduce cost and schedule. The PJFF ductwork for these units (associated with the mercury control project) will remain permanent and should not interfere with construction or the FGD tie-in outage activities. The tie-in outage for each of these units would consist of a single point tie-in with an approximate duration of two to three weeks. These outages could be kept to a minimum if the FGD bypass dampers could be installed during outages associated with the earlier AQC projects.

Units 1 & 2

The wet FGD facility layout for Units 1 & 2 offers considerably better access for cranes and equipment than the dry FGD layout. The equipment is spread out and it is not entirely confined within the area bounded by the existing coal conveyors. The sequence of installation would still be critical but would be easier than for the dry FGD layout. The new stack would again be critical path for Units 1 & 2 due to the exclusion zone required during stack erection. As with Units 3 & 4, most of the ductwork could be modularized or ground fabricated. Unit 1 ductwork and booster fan installation will be more difficult due to limited access after Unit 2 is operating. The pipe bridge location and elevation is critical such that it does not block access for cranes and equipment to construct Unit 1. The permanent PJFF ductwork will not significantly interfere with installation of the booster fans or ductwork The PJFF ductwork (for mercury removal) for these units will be considerably shorter than for Units 3 & 4, and again, remain permanent and should not interfere with construction or FGD tie-in outage activities. The tie-in outage duration for these units would be similar to Units 3 & 4, approximately two to three weeks each.

7.10.2 Dry FGD

Units 3 & 4

The majority of the dry FGD facility for Units 3 & 4 will be located north of the Unit 4 coal conveyor. This will ease the installation for Unit 3 by allowing greater accessibility for cranes and equipment. The majority of the Unit 3 supply duct and return duct to the existing stack could be modularized or ground fabricated modules, only limited by transporting them to the erection site and crane selection. Per the study layout, all of Unit 4 equipment is "inside" the construction area, which will limit access and productivity for this unit. The pipe bridge, depending on its location and elevation, and the temporary ductwork from the PJFF's may cut off access and ability to install large ductwork modules for Unit 4. The duration of a final outage for this system could be quite substantial depending on the location of the temporary ductwork and how much of it would need to be removed during the outage. Other outage activities would include coating the existing stack liners, coating the inlet ducts, tie-in of the new PJFF extensions, tie-in new ductwork to the PJFF inlet and outlet, and tie-in duct to the damper at the stack. Additional detailing is required to determine accurate outage durations, but anywhere from 10 to 14 weeks is highly possible.

Units 1 & 2

The entire dry FGD facility for Units 1 & 2 will be confined between existing coal conveyors. Construction of these units will be very challenging for a variety of reasons. The sequence of construction will be very critical due to the limited space and accessibility to the erection site for cranes and equipment. The ductwork will require long radius picks which will limit the size of ground fabricated duct modules, require larger cranes and increase field erection labor. It should be considered to make the tie-ins and install dampers, including some of the ductwork, during an earlier outage while there is greater access to the area. Appropriate measures must be taken to ensure the safety of all personnel and equipment if this is done. The PJFF is located where it makes sense for

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the final layout, but will require extensive "temporary ductwork" that not only increases cost to install and then remove, but also significantly adds to the congestion and safety during construction. The study arrangement of the dry scrubbers, duct work, PJFF's and booster fans aligns well with starting Unit 2 first. One of the difficulties will be the installation of the Unit 1 booster fans while Unit 2 is running, unless they could be installed and protected at the same time as Unit 2. The Unit 1 ductwork and scrubbers could be installed in sequence to back out of the corner, although this would add coordination and cost to the project. The same situation as Units 3 & 4 would apply for coating the stack liners, PJFF location and the substantial amount of "temporary" ductwork that would add to cost, congestion and outage duration. The outage activities would be the same as Units 3 & 4 and would require additional detailing to determine accurate outage durations.

8. RECOMMENDATION

The present study evaluated FGD operation with both a CAPP coal (future, FGD design coal) and a PRB coal (present operating coal). Based on a comparison of the net present value of the life-cycle costs of the two FGD technologies, the LSFO or wet system has a lower life-cycle cost than the dry or LSD system for both coals.

Therefore it is recommended that Southern Company proceed with the installation of a wet system to meet the SO_2 emission targets for Plant Scherer.

APPENDIX A

BASIC DESIGN BASIS – WET FGD

BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

WET FGD

1. Project Description			
Name of Client	Georgia Power and Southern Company Generation		
Project order number			
Name of project	Plant Scherer Units 1, 2, 3 & 4 Wet FGD System		
Plant location	Juliette, Georgia (near Macon)		
Elevation	465	ft above sea level	142 m
Standards, Codes and Instructions			

2. Site Conditions				
Ambient temperature	F	Max 100 F	Minimum 10 F	Performance Design 90 F
Barometric Pressure	inHg	Min. 29.07 in.Hg	Max. 31.07 in.Hg	Performance Design 29.43 in.Hg @ 465 ft above MSL 14.451 psia
Relative Humidity	%	Max 100 %	Minimum 10 %	Performance Design 85 %
Rainfall	mm/d inches	Average 5.24 mm/d 0.206 inches	Daily max recorded 5.84 mm/d	Design 5.6 mm/d
Snowfall	psf	Snow load shall be determined by ASCE 7-02 Design snow load Occupancy Importance Factor Snow Exposure Coefficient		5 psf 1.20 - 0.9 -
Wind Design wind velocity	mph	Wind load shall be determined by ASCE 7-02 Direction N/A Exposure Category : Wind Importance Factor =	C 1.15	Velocity 90 mph
Earthquake		Seismic importance factor determined by ASCE 7-02 seismic importance factor =	1.50	

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1 **BASIC DESIGN BASIS** **SCHERER UNITS 1 - 4**

2 **WET FGD**

3
4
5

3. General Process Information							
Boiler Combustion Data	Unit	Units 1, 2, 3 & 4 (identical units)					
Gross Generation	MW	[redacted]			[redacted]		
Heat Input	mmBtu/hr	9074.4			9074.4		
Heat Rate	Btu/kWh	9831.4			9300		
Excess Combustion Air **	%	25			25		
In-Leakage*	%	25			25		
Load Case		PRB Coal			Appalachian Coal		
Fuel Data		Design					
Source		PRB Coal (Primary Fuel)			Appalachian Coal (Future Back-up Fuel)		
Proximate Analysis (As Received)		Minimum	Maximum	Design	Minimum	Maximum	Design
Ash	%	2.6	7.2	5.2	4.0	19.00	10.14
Volatile Matter	%						
Fixed Carbon	%						
Heat Content	Btu/lb	8,300	9,150	8,600	10,500	13,400	12,800
Sulfur	%	0.1	0.90	0.3	0.50	1.50	1.50
Evaluation Coal Analysis		PRB Coal			Appalachian Coal		
		Minimum	Maximum	Design	Minimum	Maximum	Design
Moisture	%	24.6	29.5	27.23	5.25	7.89	6.35
ASH	%	2.60	7.20	5.20	13.00	4.50	9.24
CARBON	%	48.2	54.60	51.21	70.83	73.21	71.30
HYDROGEN	%	2.40	4.00	3.43	4.39	4.74	4.54
NITROGEN	%	0.40	1.50	0.69	1.31	1.56	1.39
SULFUR	%	0.10	0.90	0.30	0.64	1.50	1.50
OXYGEN	%	9.60	13.00	11.93	4.53	6.43	5.49
CHLORINE	ppm-w	30	150	100	68	2167	2167
FLUORINE	ppm-w	32	100	53	62	132	132
Total	%	n/a	n/a	100.0	100.0	100.0	100.0
HEAT CONTENT	Btu/lb	8,300	9,150	8,600	10,500	13,400	12,800

* Air in-leakage total for air heater(15%), ESP(5%) & baghouse(5%)

** Includes 5% design margin.

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BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

WET FGD

Coal Trace Analysis - Statistics		PRB Coal			Appalachian Coal		
		Minimum	Maximum	Medium	Minimum	Maximum	Medium
As	mg/kg	0.3	3.5	0.8	3.8	9	5.3
Ba	mg/kg	190	340	240	30	320	100
Be	mg/kg	0.1	2.4	0.2	1.6	4.4	2.7
B	mg/kg	NA	NA	NA	NA	NA	NA
Cd	mg/kg	0.02	0.28	0.04	0.04	0.07	0.05
Cl	mg/kg	30	204	46	58	1757	1534
Co	mg/kg	1.4	3.6	2.1	6.6	14.7	9.6
Cr	mg/kg	2	8	3	12	20	18
Cu	mg/kg	7	14	10	16	27	20
F	mg/kg	32	99	52	62	126	82
Hg	mg/kg	0.03	0.1	0.06	0.02	0.06	0.04
Li	mg/kg	NA	NA	NA	NA	NA	NA
Mg	% by Wt	0.09	0.2	0.15	0.05	0.14	0.06
Mn	mg/kg	0	36	8	7	76	21
Mo	mg/kg	NA	NA	NA	NA	NA	NA
Na	mg/kg	0.04	0.08	0.06	0.02	0.09	0.04
Ni	mg/kg	2	10	3	12	24	16
Pb	mg/kg	0.9	3.6	1.9	5.5	11	8.4
Sb	mg/kg	0	0.4	0.1	0.3	2.1	0.9
Se	mg/kg	0.25	2	0.5	2.3	4.17	2.5
Sr	mg/kg	0	0	0	0	0	0
V	mg/kg	7	23	11	24	44	34
Zn	mg/kg	2	32	7	8	21	14

There are two flue gas cases for FGD design basis.

Case	Load and Fuel	Relevance
Case 1: Max Load, PRB Coal	923MW, 0.31%S 8,600 Btu/lb PRB	Primary fuel will be PRB. Primary scrubber design case with 96% SO removal. The FGD system is to be robust and rigorous for this case, with complete redundancy and equipment sizing margins.
Case 2: Max. Load, Appalachian Coal	923MW, 1.5%S 12,600 Btu/lb Appalachian	Appalachian coal may be used in future. Secondary scrubber design case with 96% SO_2 removal. The FGD system is to be robust and rigorous for this case, with complete redundancy and equipment sizing margins.

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BASIC DESIGN BASIS SCHERER UNITS 1 - 4

WET FGD

Raw flue gas condition at Absorber Inlet	Case # Case Description	1 0.3% Sulfur Max. 923MW PRB	2 1.5% Sulfur Max. 923MW Appalachian				
Mass flow	lb/hr	11,636,000	11,034,000				
Flue gas pressure	in. WG	12	12				
Volume flow	acfm	3,935,000	2,685,000				
at 68F	scfm-w	2,583,000	2,419,000				
O2	lb/hr	800,900	782,600				
N2	lb/hr	7,830,700	7,654,500				
Ar	lb/hr	134,300	131,300				
CO2	lb/hr	1,976,800	1,840,800				
SO2	lb/hr	6,325	21,250				
SO3	lb/hr	127	425				
H2O	lb/hr	886,500	601,800				
HCl	lb/hr	110.00	1,460.00				
HF	lb/hr	60.00	100.00				
H2O	vol%	7.62	5.45				
O2	vol%	6.88	7.09				
CO2	vol%	17.00	16.68				
SO2	ppm-d	298	1,023				
SO3	ppm-d	6	20				
HCl	ppm-d	10	135				
HF	ppm-d	9	15				
Particulate matter	lb/hr	453.70	453.70				
	lb/mmBtu	0.05	0.05				
	gr/scf-d	0.044	0.044				
Temperature	F	355	355				
Pressure (assumed, Advatech to verify)	in wg	12	12				
$SO_2 \rightarrow SO_3$ conversion in boiler	%	1	1				
$SO_2 \rightarrow SO_3$ conversion in SCR	%	1	1				
Clean gas condition							
Gas temperature	F	135-145	130-140				
SO2	lb/h	126.5	850.0				
	ppm(d)	5.9	41.0				
Particulate matter	lb/hr	113.43	113.43				
	lb/mmBtu	0.012	0.012				
Mist	gpm/ft2	0.0005	0.0005				
Desulfurization efficiency	%	98.0	98.0				
Particulate matter removal	%	75%	75%				
FGD process		Wet Limestone-Gypsum Forced Oxidation Process					
Byproduct gypsum							

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BASIC DESIGN BASIS SCHERER UNITS 1 - 4

WET FGD

Base Case:		Disposable Grade (not dewatered)			
Alternate: The properties specified to the right. These are required by contract with the wallboard manufacturer. The gypsum dewatering system must be designed to include operating margin on these constraints.		Wallboard Quality CaSO4·2H2O CaSO3·½H2O SiO2 Fe2O3 R2O3 Cl Total soluble salts pH Mean Particle Size Moisture content	94% min 1.0% max 1.0% max 1.5% max 3.5% max 120 ppm max 600 ppm max 6 - 8 20 - 65 microns 10% max	ASTM C471 TGA AA AA AA Sp. Ion Elect. USGC method USGC method Laser Diffract. At 110 deg F	The gypsum byproduct shall not be toxic or hazardous as defined under applicable federal or state laws. The gypsum byproduct shall also not contain and toxic or hazardous constituents in concentrations which would restrict its use in the manufacture of or its end use as wallboard.
Bulk density	lb/ft3	62 lb/ft3 for gypsum storage sizing			

Limestone		Design Basis	Range	
Type				
Receiving particle size	inch	3/4 X 0		
Chemical composition				
CaCO3 Total	wt%-d	90.00		
MgCO3	wt%-d	0.75 Soluble		
		0.25 Inert		
Inerts	wt%-d	9.00		
Moisture	wt%	8.00 Max		
Limestone grindability	kW/ston	n/a		
Bulk density	lb/ft3	80 lb/ft3 for structural load, 62 lb/ft3 for volume capacity		
Reactivity	%	80		

Makeup water name	-	Service water pond		
B.L		Intake from pond		
Temperature at B.L	F	Ambient		
Pressure at B.L	psig	Atmospheric		
Composition*				
Magnesium	ppm	1.6		
Calcium	ppm			
Sodium	ppm			
Potassium	ppm			
Chloride	ppm			
Bicarbonate	ppm			
Sulfate	ppm	10		
Iron	ppm	0.68		
Silica	ppm			
pH s.u.	-			
Turbidity, NTU	ppm			
TOC	ppm	2		
COD	ppm	12		
TSS	ppm	12		
Total Hardness	ppm as $CaCO_3$			

*From 1988 data, will obtain more current data.

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BASIC DESIGN BASIS SCHERER UNITS 1 - 4

WET FGD

Cooling Water (Raw water, open loop)		Supply		Return			
Pressure	psi	Atmospheric	psi	40	psi		
Temperature (Max)	F	See Makeup Water Conditions	deg F	103	deg F		
Air							
Name		Instrument			Service		
Supply pressure	psig	Max	Advatech Scope (No existing capacity)		Max	Advatech Scope (No existing capacity)	
	psig	Min	Advatech Scope (No existing capacity)		Min	Advatech Scope (No existing capacity)	
Supply temperature	F	Max	Advatech Scope (No existing capacity)		Max	Advatech Scope (No existing capacity)	
	F	Min	Advatech Scope (No existing capacity)		Min	Advatech Scope (No existing capacity)	
Dew point	F		Dry, Oil-free (-40F)			Dry, Oil-free (-40F)	
Steam							
Supply pressure	psig	Max	N/A				
	psig	Min	N/A				
Supply temperature	F	Max	N/A				
	F	Min	N/A				
Electrical Power	V - F - Hz	>/= 250HP	4160	3φ	60Hz	Advatech Scope (as required)	
		< 250HP	480	3φ	60Hz	Advatech Scope (as required)	

4. System Design Requirement	
Gas Path System	
Duct	1 x 100 % Capacity
Velocity	60 ft/s max
By-pass	To existing stack
Stack	1 x % Capacity
type	Wet stack
Gas Velocity	45 f/s maximum
Height	675 ftH (preliminary) — same as Bowen
ID Booster Fan	2 x 50 % Capacity Axial
ID Booster Fan Test Block	15 % Flowrate margin on Case 1 (923kW) gas flow
ID Booster Fan Test Block	32 % Pressure margin on Case 1 (923MW) SPR
Limestone Receiving System	(Limestone Bulk Storage)
System capacity	1+0 x 100 % Capacity at 1.5% S Coal (future)***
Storage Capacity	30 days at 1.5% S coal (future)***
Feeder capacity	1+ 1 x 100 % Capacity at 1.5% S Coal (future)***
Conveyor capacity	1+ 1 x 100 % Capacity at 1.5% S Coal (future)***
Operation time	24 hrs per day
Limestone Supply System	(feed to Wet Ball Mill)
System capacity	1+1 x 100 % Capacity at 1.5% S Coal (future)***
Storage Capacity	8 hrs at 1.5% S coal (future)***
Feeder capacity	1+1 x 100 % Capacity
Conveyor capacity	1+1 x 100 % Capacity
Operation time	24 hrs per day

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BASIC DESIGN BASIS SCHERER UNITS 1 - 4

WET FGD

Limestone Supply System	*(Slurry feed)*
System Capacity	1 x 100 % Capacity at 1.5% S Coal (future)***
Slurry Tank Storage Capacity	2 hrs at 1.5% S coal (future)***
Limestone slurry feed pump	2 x 100 % Capacity at 1.5% S Coal (future)***
LS prep. area sump/pump/agitator	1 set of 1 + 1 pumps, 1 + 0 agitator
Operation time	24 hrs per day
Absorption System	
Operation time	24 hrs per day
Absorber recirculation pumps	As required + 1 stand-by for 96% SO2 Removal @ 1.5% S coal (future)***
Jet Air Spargers	As required for 96% SO2 Removal @ 1.5% S coal (future)***
Agitator/Oxidation device	As required
Bleed pump	1+1 x 130% Capacity at 1.5% S coal (future)***
Absorber area sump/pump/agitator	1 set of 1 + 1 pumps, 1 + 0 agitator
Secondary Dewatering System	NA
Filter Feed Storage Tank	
Filtrate Tank	
Gypsum Cyclone O/F tank	
Belt Filter Washing Tank	
Belt Filter	
Operation time	
Gypsum Storage System	NA
Storage Capacity	
Front-end loader	
Operation time	

*** = 1.5% S coal may be used in the future and therefore is used as the design coal. The plant is currently using 0.3% S coal.

Utility Systems		
Process Water Tank	N/R	
Process Water Intake Pumps	1+1 x 100 % Capacity	(If Req'd)
FGD Plant Air Compressor	1+1 x 100 % Capacity	

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APPENDIX B

BASIC DESIGN BASIS – DRY FGD

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BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

DRY FGD

1. Project Description			
Name of Client	Georgia Power and Southern Company Generation		
Project order number			
Name of project	Plant Scherer Units 1, 2, 3 & 4 Dry FGD System		
Plant location	Juliette, Georgia (near Macon)		
Elevation	465	ft above sea level	142 m
Standards, Codes and Instructions			

2. Site Conditions				
Ambient temperature	F	Max 100 F	Minimum 10 F	Performance Design 90 F
Barometric Pressure	inHg	Min. 29.07 in.Hg	Max. 31.07 in.Hg	Performance Design 29.43 in.Hg @ 465 ft above MSL 14.451 psia
Relative Humidity	%	Max 100 %	Minimum 10 %	Performance Design 85 %
Rainfall	mm/d inches	Average 5.24 mm/d 0.206 inches	Daily max recorded 5.84 mm/d	Design 5.6 mm/d
Snowfall	psf	Snow load shall be determined by ASCE 7-02 Design snow load Occupancy Importance Factor Snow Exposure Coefficient		5 psf 1.20 - 0.9 -
Wind Design wind velocity	mph	Wind load shall be determined by ASCE 7-02 Direction N/A Exposure Category : Wind Importance Factor =	C 1.15	Velocity 90 mph
Earthquake		Seismic importance factor determined by ASCE 7-02 seismic importance factor =	1.50	

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BASIC DESIGN BASIS SCHERER UNITS 1 - 4

DRY FGD

3. General Process Information							
Boiler Combustion Data	Unit	Units 1, 2, 3 & 4 (Identical units)					
Gross Generation	MW	[redacted]			[redacted]		
Heat Input	mmBtu/hr	9074.4			9074.4		
Heat Rate	Btu/kWh	9031.4			9300		
Excess Combustion Air **	%	25			25		
In-Leakage*	%	20			20		
Load Case		PRB Coal			Appalachian Coal		
Fuel Data		Design					
Source		PRB Coal (Primary Fuel)			Appalachian Coal (Future Back-up Fuel)		
Proximate Analysis (As Received)		Minimum	Maximum	Design	Minimum	Maximum	Design
Ash	%	2.6	7.2	5.2	4.0	19.00	10.14
Volatile Matter	%						
Fixed Carbon	%						
Heat Content	Btu/lb	8,300	9,150	8,600	10,500	13,400	12,800
Sulfur	%	0.1	0.90	0.3	0.50	1.50	1.50

Evaluation Coal Analysis		PRB Coal			Appalachian Coal		
		Minimum	Maximum	Design	Minimum	Maximum	Design
Moisture	%	24.8	29.5	27.23	5.25	7.09	6.35
ASH	%	2.60	7.20	5.20	13.00	4.50	9.24
CARBON	%	48.2	54.60	51.21	70.83	73.21	71.30
HYDROGEN	%	2.40	4.00	3.43	4.39	4.74	4.54
NITROGEN	%	0.40	1.50	0.69	1.31	1.56	1.39
SULFUR	%	0.10	0.90	0.30	0.64	1.50	1.50
OXYGEN	%	9.60	13.00	11.93	4.53	6.43	5.49
CHLORINE	ppm-w	30	150	100	68	2167	2167
FLUORINE	ppm-w	32	100	63	62	132	132
Total	%	n/a	n/a	100.0	100.0	100.0	100.0
HEAT CONTENT	Btu/lb	8,300	9,150	8,600	10,500	13,400	12,800

* Air in-leakage total for air heater(15%) & ESP(5%)

** Includes 5% design margin.

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BASIC DESIGN BASIS SCHERER UNITS 1 - 4

DRY FGD

Coal Trace Analysis - Statistics		PRB Coal			Appalachian Coal		
		Minimum	Maximum	Meduim	Minimum	Maximum	Medium
As	mg/kg	0.3	3.5	0.6	3.8	9	5.3
Ba	mg/kg	190	340	240	30	320	100
Be	mg/kg	0.1	2.4	0.2	1.6	4.4	2.7
B	mg/kg	NA	NA	NA	NA	NA	NA
Cd	mg/kg	0.02	0.28	0.04	0.04	0.07	0.05
Cl	mg/kg	30	204	46	68	1757	1534
Co	mg/kg	1.4	3.8	2.1	6.8	14.7	9.6
Cr	mg/kg	2	6	3	12	20	16
Cu	mg/kg	7	14	10	18	27	20
F	mg/kg	32	99	52	62	126	82
Hg	mg/kg	0.03	0.1	0.06	0.02	0.06	0.04
Li	mg/kg	NA	NA	NA	NA	NA	NA
Mg	% by Wt	0.09	0.2	0.15	0.05	0.14	0.06
Mn	mg/kg	0	36	8	7	76	21
Mo	mg/kg	NA	NA	NA	NA	NA	NA
Na	mg/kg	0.04	0.08	0.05	0.02	0.09	0.04
Ni	mg/kg	2	10	3	12	24	16
Pb	mg/kg	0.9	3.6	1.9	5.5	11	6.4
Sb	mg/kg	0	0.4	0.1	0.3	2.1	0.9
Se	mg/kg	0.25	2	0.5	2.3	4.17	2.5
Sr	mg/kg	0	0	0	0	0	0
V	mg/kg	7	23	11	24	44	34
Zn	mg/kg	2	32	7	8	21	14

There are two flue gas cases for FGD design basis.

Case	Load and Fuel	Relevance
Case 1: Max Load, PRB Coal	923MW, 0.3%S 8,600 Btu/lb PRB	Primary fuel will be PRB. Primary scrubber design case with 92.8% SO removal. The FGD system is to be robust and rigorous for this case, with complete redundancy and equipment sizing margins.
Case 2: Max. Load, Appalachian Coal	923MW, 1.5%S 12,600 Btu/lb Appalachian	Appalachian coal may be used in future. Secondary scrubber design case with 95% SO_2 removal. The FGD system is to be robust and rigorous for this case, with complete redundancy and equipment sizing margins.

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BASIC DESIGN BASIS SCHERER UNITS 1 - 4

DRY FGD

Raw flue gas condition at Spray Dryer Absorber Inlet	Case # Case Description	1 0.3% Sulfur Max. 923MW PRB	2 1.5% Sulfur Max. 923MW Appalachian				
Mass flow (Incl. ACI)	lb/hr	11,283,000	10,689,000				
Flue gas pressure	in. WG	0.0	0.0				
Volume flow	acfm	3,904,000	3,651,000				
at 88F	scfm-w	2,503,000	2,341,000				
O2	lb/hr	720,800	704,300				
N2	lb/hr	7,570,000	7,400,000				
Ar	lb/hr	120,900	126,900				
CO2	lb/hr	1,977,000	1,841,000				
SO2	lb/hr	6,262	21,035				
SO3	lb/hr	79	266				
H2O	lb/hr	877,300	592,600				
HCl	lb/hr	109.00	1,456.00				
HF	lb/hr	59.00	99.00				
H2O	vol%	12.50	9.03				
O2	vol%	5.78	6.04				
CO2	vol%	11.53	11.48				
SO2	ppm-d	290	990				
SO3	ppm-d	3	13				
HCl	ppm-d	10	120				
HF	ppm-d	9	15				
Particulate matter	lb/hr	2,087	2,060				
	lb/mmBtu	0.230	0.227				
	gr/scf-d						
Temperature	F	350	350				
Pressure	in wg	0.0	0.0				
$SO_2 \rightarrow SO_3$ conversion in boiler	%	1	1				
$SO_2 \rightarrow SO_3$ conversion in SCR	%	1	1				
Clean gas condition							
Gas temperature	F	169	162				
SO2	lb/h	454	1,064				
	ppm(d)	20.0	49.0				
Particulate matter	lb/hr	136	136				
	lb/mmBtu	0.015	0.015				
Mist	gpm/ft2	NA	NA				
Desulfurization efficiency	%	92.8	95.0				
Particulate matter removal	%	99.82	99.82				
FGD Process		Lime Spray Dryer Process					
FGD Byproduct Mixture							
Base Case		Landfill					

BASIC DESIGN BASIS SCHERER UNITS 1 - 4

DRY FGD

Composition	wt%	Ca(OH)2	15.0%	
	wt%	CaSO3·½H2O	80.0%	
	wt%	CaSO4·2H2O	incl. above	
	wt%	CaCl2-2H20	incl. above	
	wt%	Inerts + Carbon	incl. above	
	wt%	Flyash	3.0%	
	wt%	Moisture	2.0%	
		Mean Particle Size		
Bulk density	lb/ft3	103 lb/ft3 for landfill sizing		
Lime		Design Basis	Range	
Type		Pebble		
Receiving particle size	inch	3/4 X 0		
Chemical Composition				
CaO	wt%-d	90.0		
Inerts	wt%-d	10.0		
Moisture	wt%	0.0		
Grindability	kW/ston			
Bulk density	lb/ft3	70 lb/ft3 for structural load, 60 lb/ft3 for volume capacity of silos		
Reactivity	%			
Makeup Water				
Name	-	Service water pond		
B.L		Intake from pond		
Temperature at B.L	F	Ambient		
Pressure at B.L	psig	Atmospheric		
Composition*				
Magnesium	ppm	1.5		
Calcium	ppm			
Sodium	ppm			
Potassium	ppm			
Chloride	ppm			
Bicarbonate	ppm			
Sulfate	ppm	10		
Iron	ppm	0.68		
Silica	ppm			
pH s.u.	-			
Turbidity, NTU	ppm			
TOC	ppm	2		
COD	ppm	12		
TSS	ppm	12		
Total Hardness	ppm as $CaCO_3$			

*From 1988 data, will obtain more current data.

BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

DRY FGD

Cooling Water							
(Raw water, open loop)			Supply		Return		
Pressure	psi	Atmospheric	psi	40	psi		
Temperature (Max)	F	See Makeup Water Conditions	deg F	103	deg F		
Air							
Name		Instrument			Service		
Supply pressure	psig	Max			Max		
	psig	Min			Min		
Supply temperature	F	Max			Max		
	F	Min			Min		
Dew point	F	Dry, -38 deg (-40F)					
Steam							
Supply pressure	psig	Max	N/A				
	psig	Min	N/A				
Supply temperature	F	Max	N/A				
	F	Min	N/A				
Electrical Power	V - F - Hz	> 250HP	4160	3φ	60Hz	Advatech Scope (as required)	
		< 250HP	480	3φ	60Hz	Advatech Scope (as required)	

4. System Design Requirement	
Gas Path System	
Duct	1 x 100 % Capacity
Velocity	60 ft/s max
By-pass	To existing stack
Stack	Existing (liner to be coated)
type	Dry stack
Gas Velocity	Existing
Height	Existing
ID Booster Fan	2 x 50 % Capacity Axial
ID Booster Fan Test Block	15 % Flowrate margin on Case 1 (923MW) gas flow
ID Booster Fan Test Block	32 % Pressure margin on Case 1 (923MW) SPR
Lime Receiving System	*(Lime Bulk Storage)*
System capacity	1+0 x 100 % Capacity at 1.5% S Coal (future)***
Storage Capacity	30 days at 1.5% S coal (future)*** (6 silos)
Feeder capacity	1+ 0 x 100 % Capacity at 1.5% S Coal (future)***
Conveyor capacity	1+ 0 x 100 % Capacity at 1.5% S Coal (future)***
Operation time	24 hrs per day
Lime Supply System	*(feed to Vortimill Slaker)*
System capacity	1+0 x 33 % Capacity at 1.5% S Coal (future)*** per silo
Slurry Storage Tank Capacity	8 hrs at 1.5% S coal (future)*** - common for 6 slakers
Feeder capacity	1+0 x 33 % Capacity per silo
Lime prep. area sump/pump/agitator	1 set of 1 + 1 pumps, 1 + 0 agitator
Operation time	24 hrs per day

BASIC DESIGN BASIS **SCHERER UNITS 1 - 4**

DRY FGD

Limestone Supply System	*(Slurry feed to SDA's))*	
System Capacity	1 x 100 % Capacity at 1.5% S Coal (future)*** per pair of units	
Slurry Feed Tank Capacity	2 hrs at 1.5% S coal (future)*** - 1 per pair of units	
Limestone slurry feed pump	1+1 x 100 % Capacity at 1.5% S Coal (future)*** per pair of units	
Operation time	24 hrs per day	
Absorption System		
Lime Spray Dryers	3+0 x 100% capacity	
Pulse Jet Fabric Filter	2+0 x 100% capacity	
Absorber area sump/pump/agitator	1 set of 1 + 1 pumps, 1 + 0 agitator - per pair of units	
Operation time	24 hrs per day	
Recycle Ash System		
Silo Storage Capacity	8 hrs - 1 silos per unit	
Mixers	1+1 x 100% per unit	
Slurry Storage Tank Capacity	4 hrs - 1 per unit	
Slurry Feed Pumps	1+1 x 100% per unit	
Operation time	24 hrs per day	
Flyash Handling System		
Storage Capacity	4 days @ 1.5% S coal (future)***	
Operation time	8-10 hrs per day	

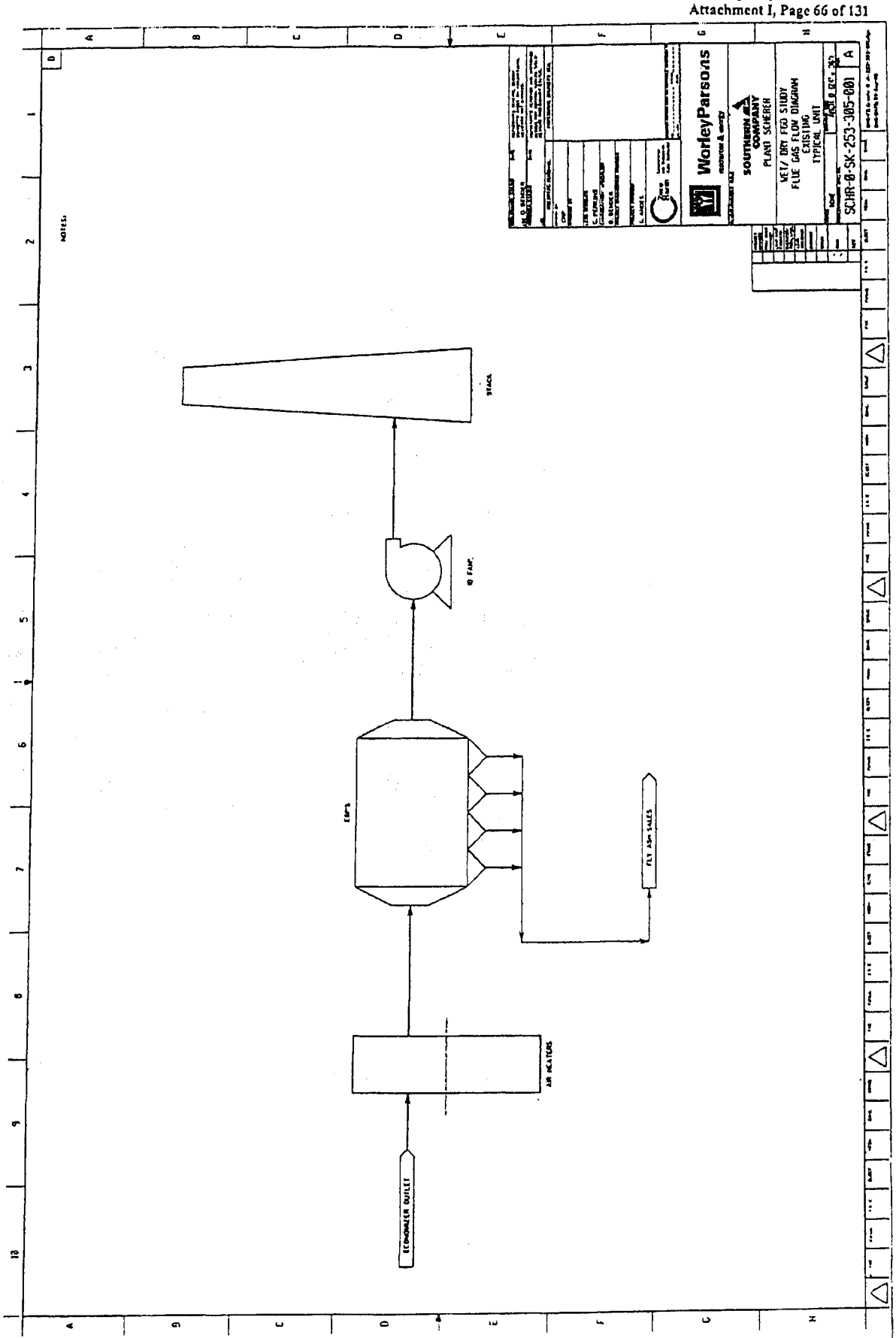
*** = 1.5% S coal may be used in the future and therefore is used as the design coal. The plant is currently using 0.3% S coal.

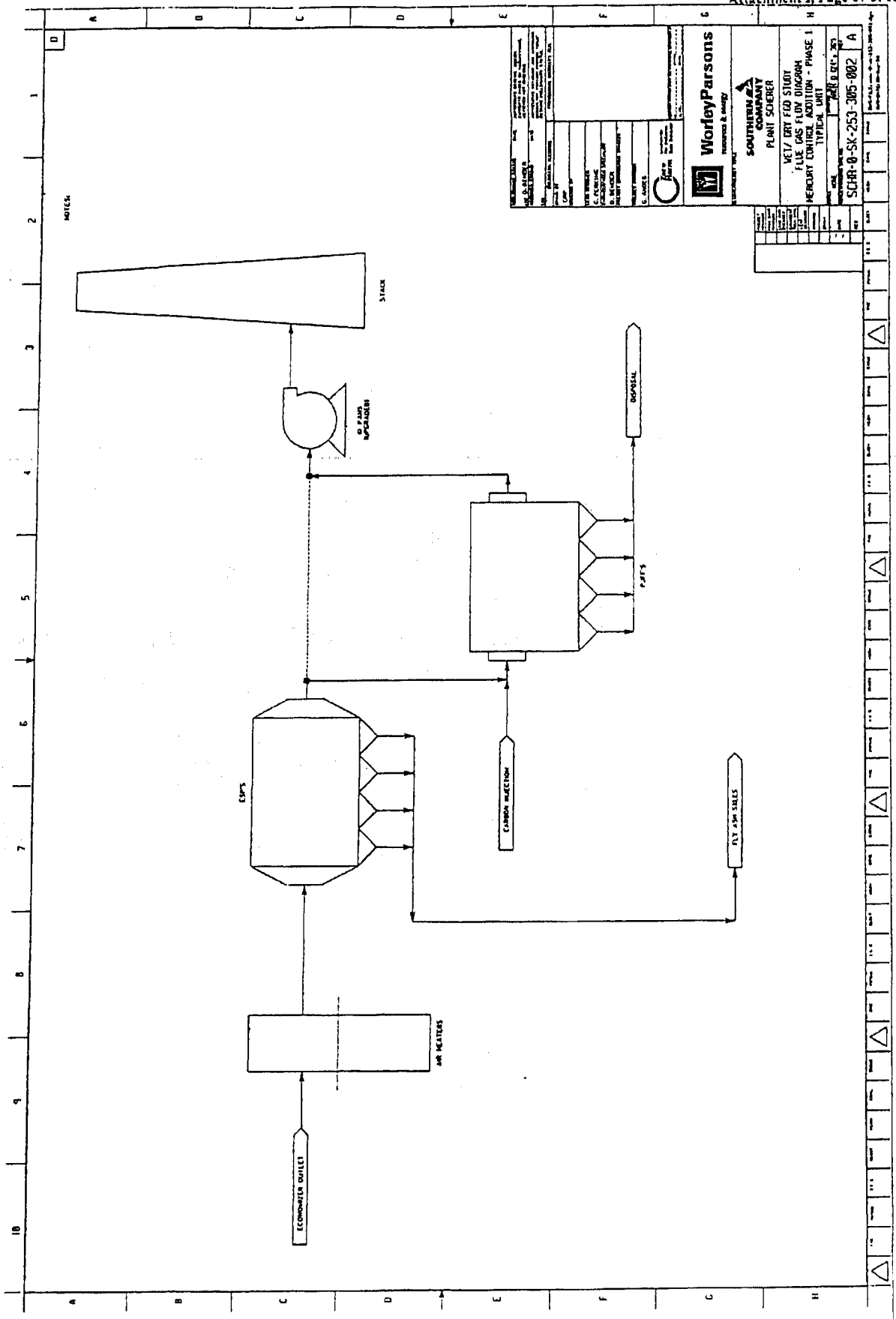
Utility Systems		
Process Water Tank	N/R	
Process Water Intake Pumps	1+1 x 100 % Capacity	if req'd
FGD Plant Air Compressor	1+1 x 100 % Capacity	

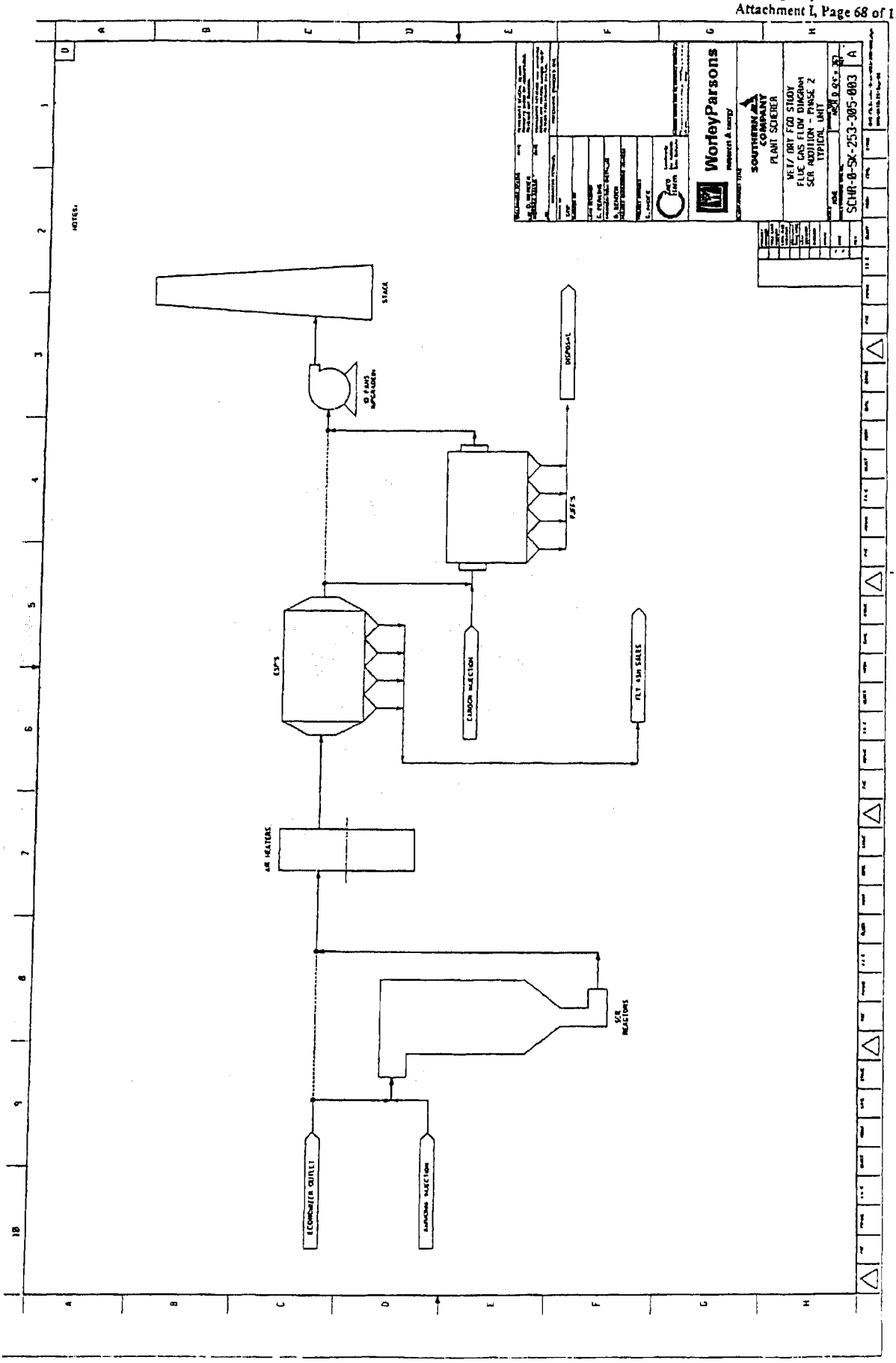
APPENDIX C

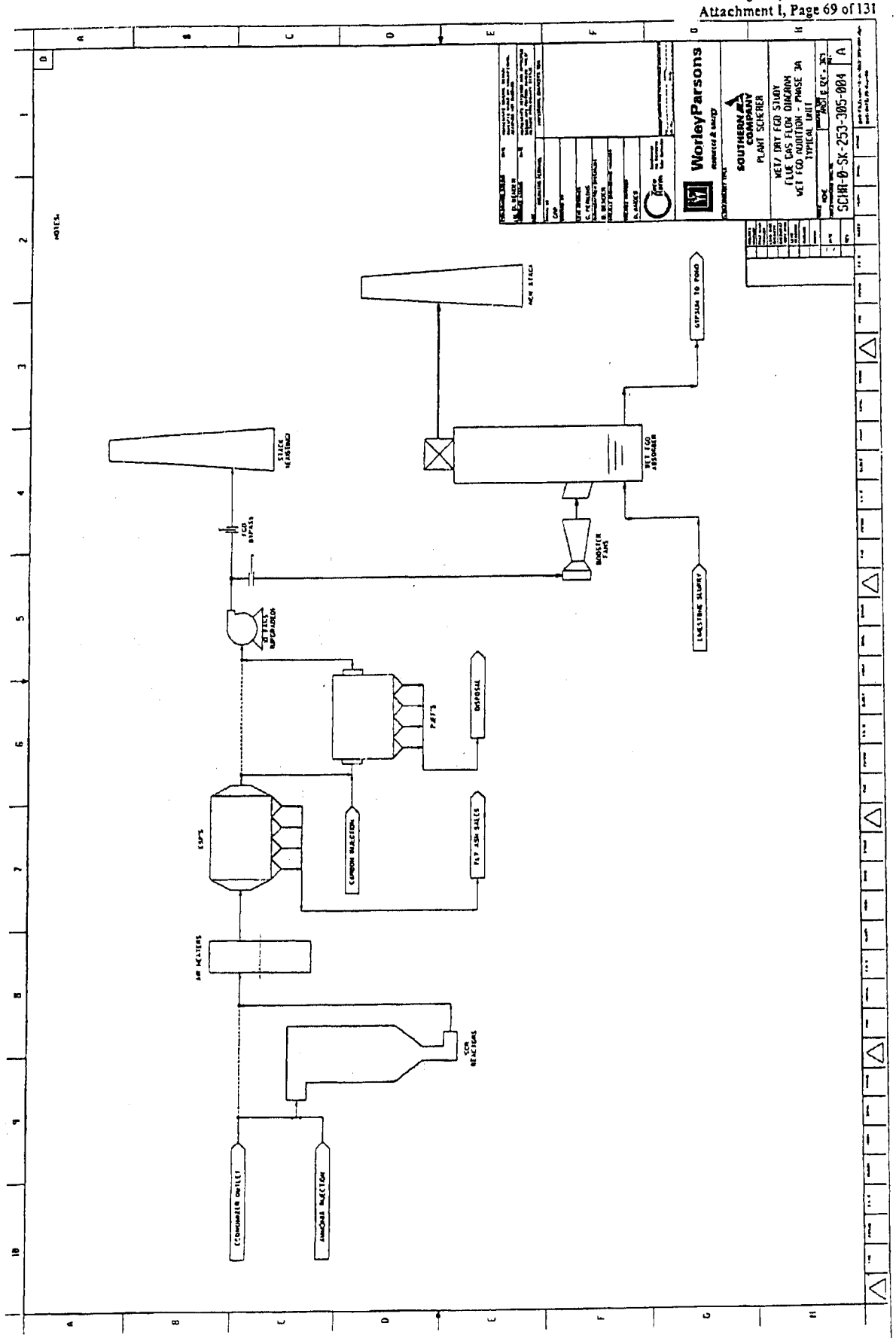
FLUE GAS FLOW DIAGRAMS

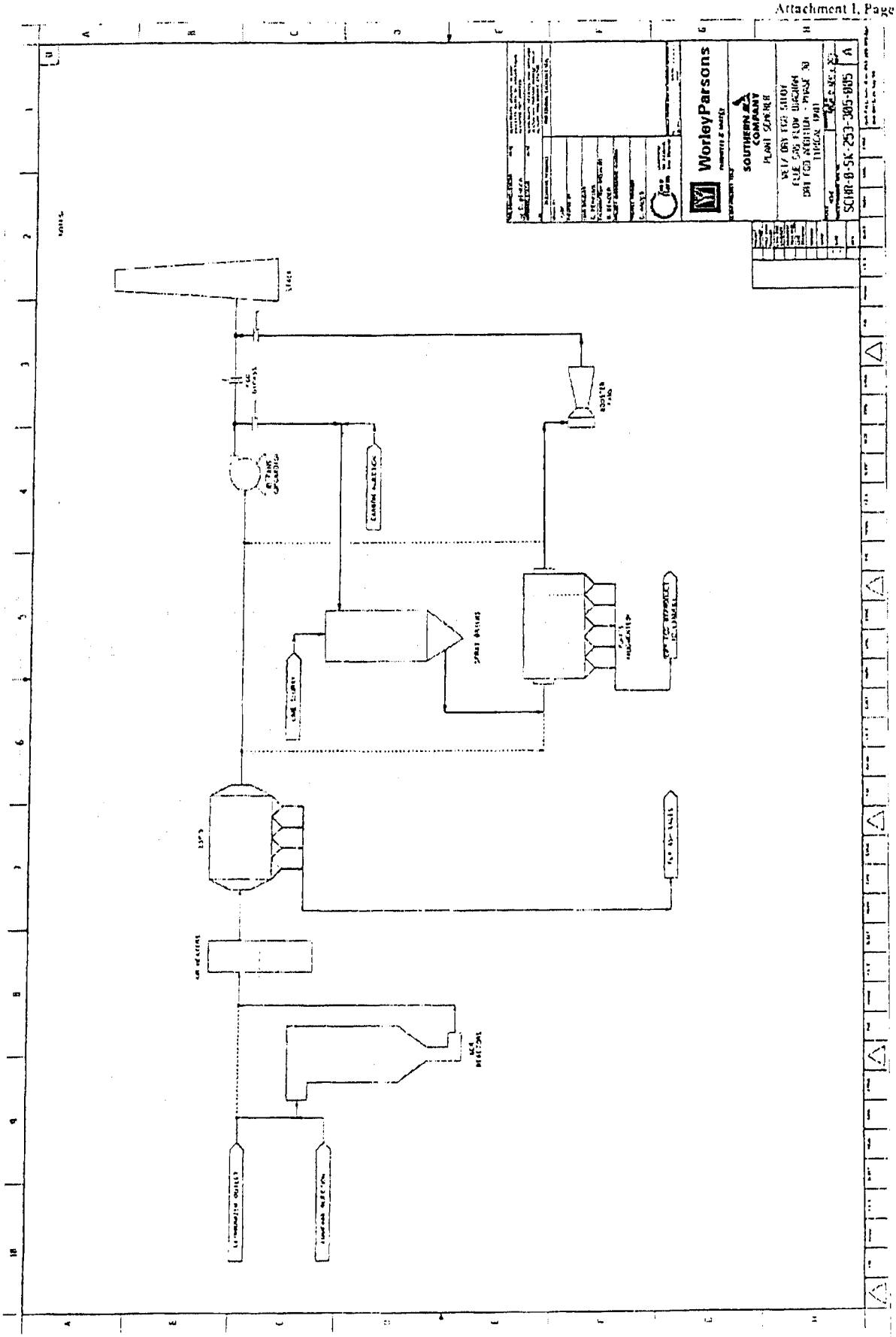
SCHR-1-SK-253-305-001
SCHR-1-SK-253-305-002
SCHR-1-SK-253-305-003
SCHR-1-SK-253-305-004
SCHR-1-SK-253-305-005


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
WET/ DRY FGD STUDY
FLUE GAS FLOW DIAGRAM
EXISTING
TYPICAL UNIT
SCHR-0-SK-253-305-001
NOTES:
STACK
ID FANS
ESPs
FLY ASH SILOS
AIR HEATERS
ECONOMIZER OUTLET


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
WET/ DRY FGD STUDY
FLUE GAS FLOW DIAGRAM
MERCURY CONTROL ADDITION - PHASE 1
TYPICAL UNIT
SCHR-0-SK-253-305-002
NOTES:
STACK
ID FANS
DISPOSAL
FABFS
ESPS
CARBON INJECTION
FLY ASH SILOS
AIR HEATERS
ECONOMIZER OUTLET


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
VEF / ORT FGD STUDY
FLUE GAS FLOW DIAGRAM
SCR ADDITION - PHASE 2
TYPICAL UNIT
SCHR-8-SK-253-305-003
NOTES:
STACK
ID FANS
DISPOSAL
FF'S
ESP'S
CARBON INJECTION
FLY ASH SILOS
AIR HEATERS
SCR REACTORS
ECONOMIZER OUTLET
AMMONIA INJECTION


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
WET/DRY FGD STUDY
FLUE GAS FLOW DIAGRAM
WET FGD ADDITION - PHASE 3A
TYPICAL UNIT
SCHR-0-SK-253-305-004
NOTES:
STACK
EXISTING
NEW STACK
GYPSUM TO POND
WET FGD
ABSORBER
FGD
BYPASS
BOOSTER
FANS
LIMESTONE SLURRY
ID FANS
EXISTING
UPGRADED
PARTS
DISPOSAL
ESPS
CARBON INJECTION
FLY ASH SILOS
AIR HEATERS
SCR
REACTORS
ECONOMIZER OUTLET
AMMONIA INJECTION


WorleyParsons
SOUTHERN COMPANY
SCHR-0-SK-253-305-9805

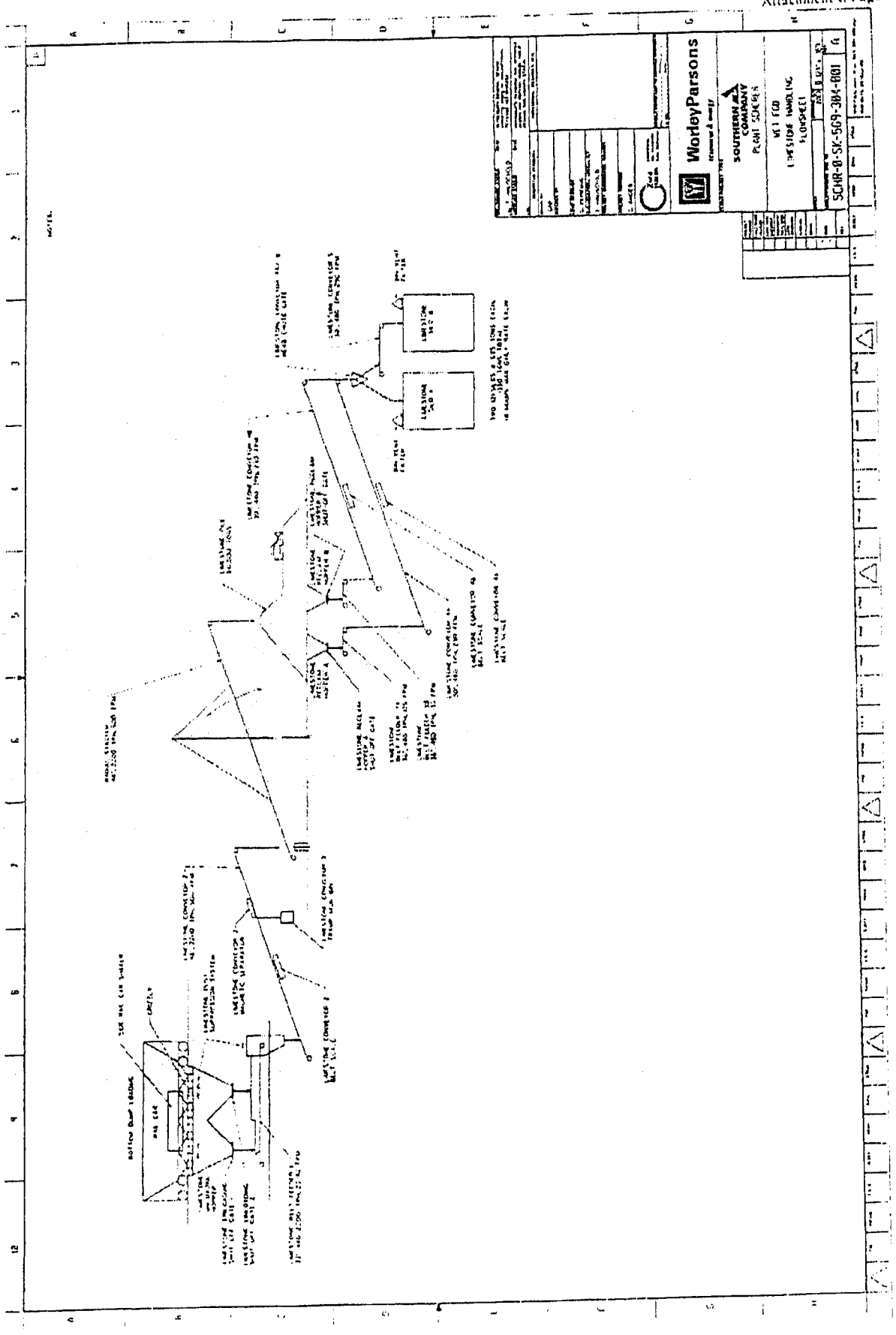
Florida Power & Light
Docket No. 070007-EI
Staff's Fourth Set of Interrogatories
Interrogatory No. 36
Attachment 1, Page 71 of 131

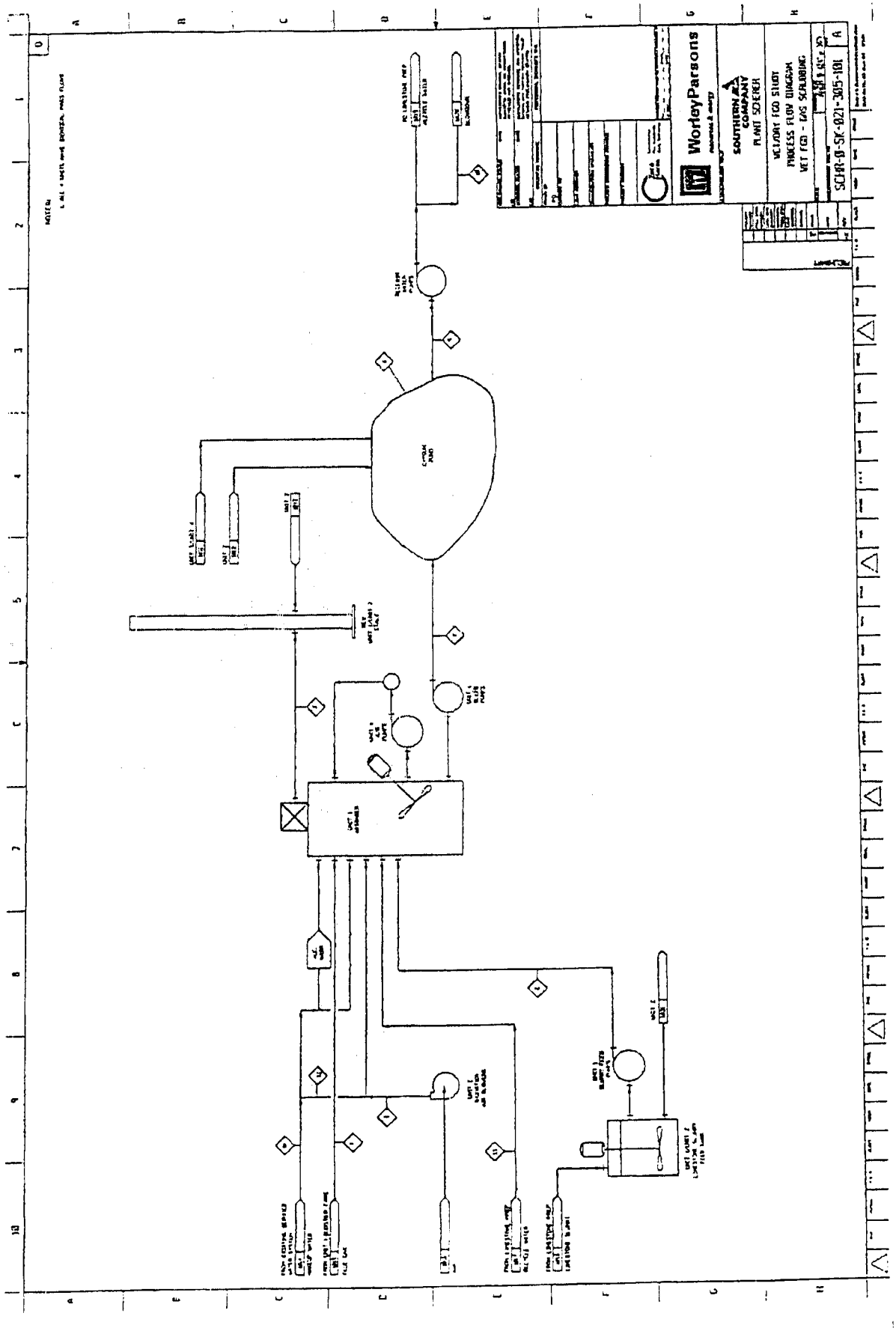
APPENDIX D

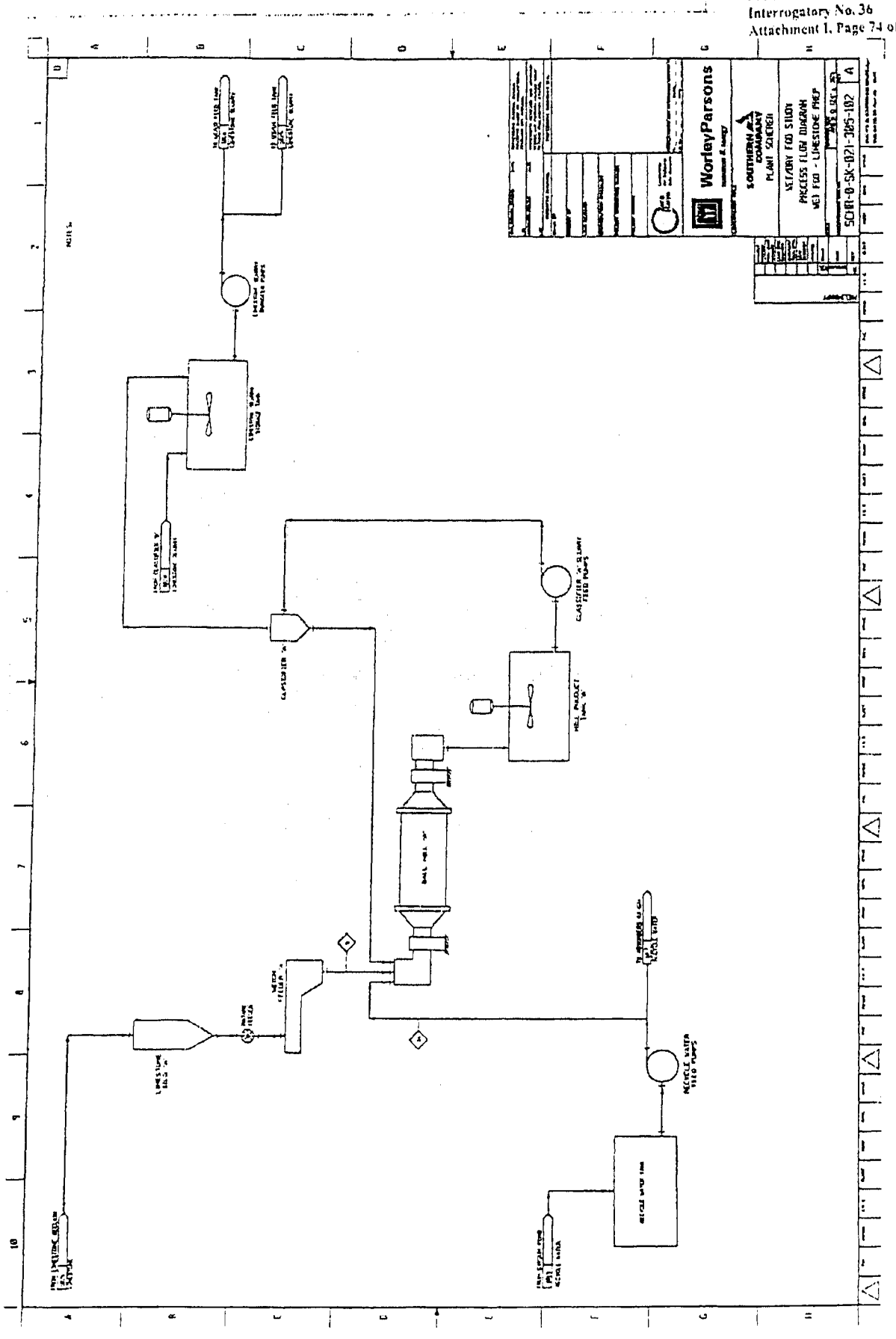
CONCEPTUAL PROCESS DESIGN – WET FGD

- Limestone Handling Flow Diagram
  SCHR-0-SK-569-304-001
- FGD Process Flow Diagram (2 shts)
  SCHR-0-SK-021-305-101
  SCHR-0-SK-021-305-102
- Combustion Calculations
- Material Balance

070007-Hearing Exhibit 000102


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
SCHR-0-SK-569-3004-0001


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
VICTORY FGD STUDY
PROCESS FLOW DIAGRAM
WET FGD - GAS SCRUBBING
SCHR-B-SK-021-305-101


WorleyParsons
SOUTHERN COMPANY
SCPR-0-SK-0021-385-102

WorleyParsons

COAL COMBUSTION CALCULATION

CLIENT NAME: Georgia Power & Southern Company
PROJECT NAME: Scherer FGD Study WRT
SUBJECT: Design Basis (MCR) - Appalachian Coal

JOB NUMBER

CALCULATION NUMBER

Coal Mine or Coal Number: Appalachian Coal

Constituent	Percent	As Fired	Basis	Moles/Hr lb	Mole %
Carbon	71.380	70.864	12.311	5.903949	5.879564
Hydrogen	4.640	4.543	2.018	2.254466	1.121444
Sulfur	1.908	1.860	32.064	0.058018	0.044758
Nitrogen	1.398	1.360	28.013	0.048552	
Moisture	6.127	6.327	18.015	0.351176	
Oxygen	5.490	5.490	31.998	0.171571	0.107127
Chlorine	0.099	0.200	35.453	0.005644	
Fluorine	0.213	0.013	18.998	0.000684	
Ash	8.245	8.245			
TOTAL	100.000	99.665			
Moisture as %	38.50	(0% dry gas)	7.326		
HHV	12,868				
Coal Heating Value	12,831				
% Difference	0.18%				

PRETREATMENT DATA	
Bar Press (psia)	29.43
Temp F	95.00
Rel Humidity %	88.00
Water Vapor Press (psi)	0.6661
lb moles/lb dry air	0.0208

Theoretical Air (0% excess)	mol fraction	Totals:
Theo Moles N2/Hr lb	0.70754	19.813.44 lbmol/hr
Theo Moles H2O/lb	0.01129	203.33 lbmol/hr
Theo Moles Ar/Lb	0.00931	372.40 lbmol/hr
Theo Moles H2O/Lb	0.26186	7,472.89 lbmol/hr
TOTALS	1.00000	28,362.06 lbmole air

Actual Air Including Excess: 504,908 Alt lbmole/hr
13,393,158 lb/hr air Mass

Flue Mass CO2/lb	0.44954
Flue Mass O2/Lb	0.41897
Total Mass CP/Lb	19.34431
Mole N2/Lb	38.48313
Mole Ar/Lb	0.46348
Total Mass W A/Lb	0.30980
Mole H2O/Lb in air	2.11548
Total Mole W A/Lb	5.018131
Total D A lb/Lb	1.428.00307
Total W A lb/Lb	1.486.01684

Ash CP/C lb	53.138	Wet	1.89883	0.71626	0.04978	36.34273	3.44977	0.43548
Vol % CP/C lb	196.007%	Wet	0.11137	0.06867	0.00388	0.72956	0.06493	0.00511
Vol % CP/C lb	120.00%	Dry	0.12185		0.00397	0.79818	0.07129	0.00557
		Mol Wt	44.00995	18.01534	64.06280	28.01343	31.99880	28.94800
Total Lb CP/C lb	1.356.344	Wet	259.85367	84.65847	3.99884	98.96.71356	110.38453	16.51493
Wgt % CP/C lb	100.00%	Wet	0.18864	0.05453	0.00193	0.69376	0.07003	0.01185
Lb CP/C lb	1,471.467	Dry	256.65.367		3.94691	10.78 F1356	110.38453	16.51493
Total Lb/hr	11.023.508	Wet	1,840,783.8	801,587.7	21,246.5	7,454,454.3	783,588.7	131,259.3

Ash	Wet	Dry
Fuel Wt	28.813	28.987
Gas Const	84.186	53.346

Ash	Wet	Dry
Mol Wt	29.200	30.367
Gas Const	82.737	80.837

Sp (lbs/lb mol)
7.357 Btu/(lbmol*F)
0.252 Btu/(lb*F)

Boiler Heat Input

Btu/Hr	Fg Rate Lb/Hr
8.87440E+09	706,936
8.87440E+09	706,936
8.87440F+09	706,936
8.87440F+09	706,936
8.87440E+09	706,936

AIR FLOW RATE CALCULATION

Temp F	%H2O Ga	lb/hr	lb/hr	ACFM
60.0	10.00	10,393,156	8.8720	3,467,336
100.0	10.00	10,393,156	8.8707	3,456,894
80.0	10.00	10,393,156	8.8733	3,363,456
74.0	10.00	10,393,156	8.8783	3,318,620
		10,393,156	8.8656	7,013,641

GAS FLOW RATE CALCULATION

Temp F	%H2O Ga	lb/hr	lb/hr	ACFM
710.0	6.00	11,033,508	0.0000	6,760,923
356.0	17.00	11,033,508	0.0499	3,085,255
345.0	12.00	11,033,508	0.0605	3,640,013
330.0	17.00	11,033,508	0.0521	3,526,348
0.0	0.00	11,033,508	0.0760	2,416,162

(SCFM)

BOILER EFFICIENCY CALC (HEAT LOSS METHOD)

Fuel Gas Temp (F, at exchanger)	330
UBC in Ash %	4.0
UBC lb/Lb	0.035
CO ppmv	0
Radiation & Other %	0.20
Air Leakage (% Boiler air)	15
Air Leakage (% Air Heat)	0.42
Air leakage gas temp (F)	346 (Usually 5-15 F in Air Heat Exchanger)
Air Heat Air Temp (F)	90

ASH DISPOSITION

Total Ash	88.580 lb/hr
Fly ash/Total Ash	0.90
Total Flyash	81,733 lb/hr
Bottom Ash	6,858 lb/hr
Ash to PSP	6.863 lb/mmBtu
Ash to ESP	81733 lb/hr

Fluid	CO2	H2O	SO2	N2	O2	AR	HCL	HF
Specific Heat - Btu/(lbmol-F)	9.5805	8.13167	10.1509	7.00452	7.21268	4.2164	6.9629	6.9629
LOSSES: Dry Gas	14384		121	664.36	6348	109	10	1

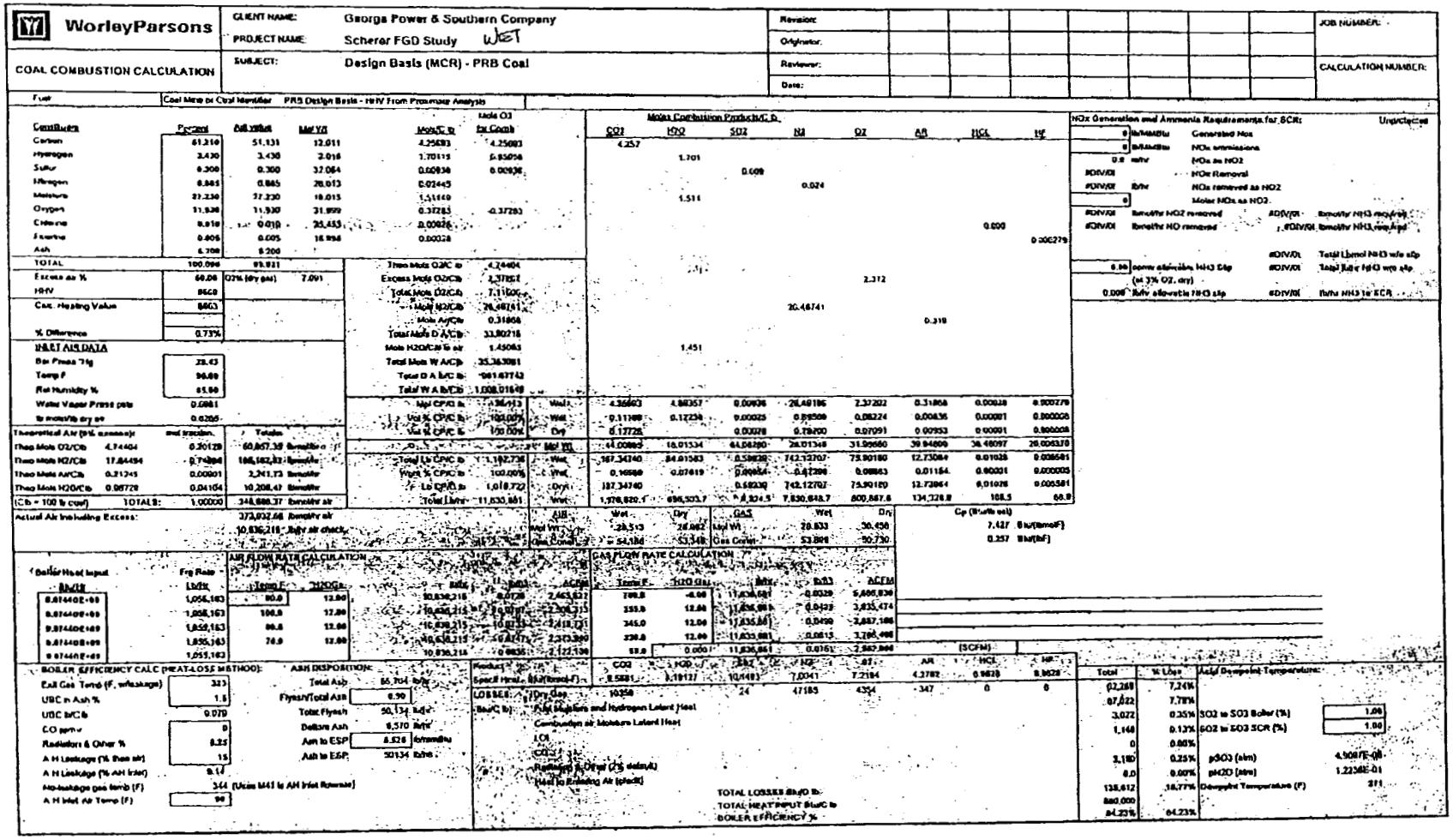
Fuel Moisture and Hydrogen Latent Heat
Combustion Air Moisture Latent Heat
LOI
CO
Radiation & Other (2% default)
Heat in Entering Air (credit)

TOTAL LOSSES Btu/Lb
TOTAL HEAT INPUT Btu/Lb
BOILER EFFICIENCY %

Total	% Loss
93,207	7.05%
54,397	4.24%
4,487	0.34%
8,313	0.49%
0	0.00%
3,300	0.38%
0.0	0.00%
156,364	12.37%
1,240,000	
87.63%	87.63%

Acid Dewpoint Temperature:

SO2 to SO3 Boiler (%)	1.00
SO2 to SO3 SCR (%)	1.00
pSO3 (atm)	1.78140E-05
pH2O (atm)	0.00736E-02
Dewpoint Temperature (F)	289



WorleyParsons

CLIENT NAME: Georgia Power & Southern Company
PROJECT NAME: Scherer FGD Study WET
SUBJECT: Design Basis (MCR) - PRB Coal

COAL COMBUSTION CALCULATION

Revision:
Originator:
Reviewer:
Date:

JOB NUMBER:
CALCULATION NUMBER:

Fuel: Coal Mine or Coal Identifier: PRB Design Basis - HHV From Proximate Analysis

Constituent	Percent	As Fired	Mol Wt	Mole O2 to C	Mole O2 to Comb
Carbon	51.210	51.131	12.011	4.25683	4.25683
Hydrogen	3.430	3.426	2.016	1.70115	1.85056
Sulfur	0.300	0.300	32.064	0.00936	0.00936
Nitrogen	0.845	0.845	28.013	0.02445	
Moisture	21.230	21.230	18.015	1.51140	
Oxygen	11.930	11.930	31.999	0.37283	-0.37283
Chlorine	0.010	0.010	35.453	0.00026	
Fluorine	0.005	0.005	18.998	0.00026	
Ash	6.200	6.200			
TOTAL	100.000	99.931			
Excess air %	60.00	O2% (dry gas)	7.091		
HHV	8800				
Calc. Heating Value	8803				
% Difference	0.03%				

INLET AIR DATA

Bar Press "Hg	28.43
Temp F	90.00
Rel Humidity %	65.00
Water Vapor Press psia	0.6881
lb moist/lb dry air	0.0265

Theo Mole O2/C lb		4.24404	
Excess Mole O2/C lb		2.37857	
Total Mole O2/C lb		7.11600	
Mole N2/C lb		26.46741	
Mole Ar/C lb		0.31868	
Total Mole D A/C lb		33.80218	
Mole H2O/C lb in air		1.45083	
Total Mole W A/C lb		35.363081	
Total D A lb/C lb		981.67743	
Total W A lb/C lb		1,008.01649	

Theoretical Air (0% excess air) — mol fraction — Totals

Theo Mole O2/Clb	4.74404	0.30129	60,857.39 lbmol/hr o
Theo Mole N2/Clb	17.64494	0.74894	186,182.83 lbmol/hr
Theo Mole Ar/Clb	0.31245	0.00001	2,241.73 lbmol/hr
Theo Mole H2O/Clb	0.98728	0.04154	10,208.47 lbmol/hr
(Clb = 100 lb coal) TOTALS:		1.00000	348,886.37 lbmol/hr air

Actual Air Including Excess: 373,032.66 lbmol/hr air; 10,836,218 lb/hr air check

	Mol Wt	Mole/C lb	Lb/C lb	Vol %
Dry CP/C lb	36.413	Wet	4.35603	4.88357
Vol % CP/C lb	100.00%	Wet	0.11969	0.12238
Vol % CP/C lb	100.00%	Dry	0.12726	
		Mol Wt	44.00995	18.01534
Total Lb CP/C lb	1,102.736	Wet	107.34740	84.01583
Wet % CP/C lb	100.00%	Wet	0.16560	0.07619
Lb CP/C lb	1,018.722	Dry	107.34740	
Total Lbs/C	11,833,861	Wet	1,978,820.1	896,503.7

Molar Combustion Products/C lb

CO2	H2O	SO2	N2	O2	Ar	HCl	HF
4.257							
	1.701						
		0.009					
			0.024				
	1.511						
						0.000	
							0.000279
				2.372			
			26.46741				
					0.318		
	1.451						

4.35603	4.88357	0.00936	26.46186	2.37202	0.31868	0.00018	0.000279
0.11969	0.12238	0.00025	0.69500	0.06224	0.00836	0.00001	0.000008
0.12726		0.00028	0.78400	0.07091	0.00953	0.00001	0.000008
44.00995	18.01534	64.06280	28.0134e8	31.99880	39.94800	36.46097	20.006378
107.34740	84.01583	0.59830	742.12707	75.90189	12.73084	0.01028	0.006581
0.16560	0.07619	0.00924	0.47206	0.08863	0.01184	0.00001	0.000005
107.34740		0.59830	742.12707	75.90189	12.73084	0.01028	0.006581
1,978,820.1	896,503.7	6,324.5	7,830,648.7	800,867.6	134,328.8	108.5	68.8

	Wet	Dry
Mol Wt	29.513	28.963
Gas Constant	54.184	53.348

	Wet	Dry
Mol Wt	29.833	30.456
Gas Constant	53.866	50.730

Cp (Btu/lb mol)
7.427 Btu/(lbmol*F)
0.257 Btu/(lbF)

NOx Generation and Ammonia Requirements for SCR: Uncontrolled

0	lb/MMBtu	Generated Nox
0	lb/MMBtu	NOx emissions
0.0	ppmv	NOx as NO2
#DIV/0!		NOx Removal
#DIV/0!	lb/hr	NOx removed as NO2
0		Moles NOx as NO2
#DIV/0!	lbmol/hr NO2 removed	#DIV/0! lbmol/hr NH3 req'd/hr
#DIV/0!	lbmol/hr NO removed	#DIV/0! lbmol/hr NH3 req'd/hr
0.00	ppmv allowable NH3 slip (at 3% O2, dry)	#DIV/0! Total Lbmol NH3 w/o slip
0.000	lb/hr allowable NH3 slip	#DIV/0! lb/hr NH3 to SCR

BOILER EFFICIENCY CALC (HEAT-LOSS METHOD):

Exit Gas Temp (F, w/leakage)	323
UBC in Ash %	1.5
UBC lb/C lb	0.079
CO ppmv	0
Radiation & Other %	0.25
A H Leakage (% flow air)	15
A H Leakage (% AH inlet)	9.17
No-leakage gas temp (F)	344 (Uses M41 to AH Inlet Formula)
A H Inlet Air Temp (F)	90

ASH DISPOSITION:

Total Ash	85,704 lb/hr
Flyash/Total Ash	0.90
Total Flyash	50,134 lb/hr
Bottom Ash	5,570 lb/hr
Ash to ESP	0.526 lb/mmBtu
Ash to ESP	50134 lb/hr

	CO2	H2O	SO2	N2	O2	Ar	HCl	HF
Product lb/C lb	3.1364	1.2527	0.0047	19.4844	1.7473	0.2347	0.0001	0.0002
Specific Heat - Btu/(lbmol-F)	8.5581	8.1917	10.1481	7.0041	7.2194	4.3782	6.9629	6.9629
LOSSES lb/C lb: Dry Gas	1.9358		24	47185	4354	-347	0	0
Fuel Moisture and Hydrogen Latent Heat								
Combustion air Moisture Latent Heat								
UBC								
CO								
Radiation & Other (2% delta-A)								
Heat to Entering Air (check)								

TOTAL LOSSES Btu/C lb:
TOTAL HEAT INPUT Btu/C lb
BOILER EFFICIENCY %

Total	% Loss	
62,269	7.21%	
67,022	7.78%	
3,022	0.35%	SO2 to SO3 Boiler (%) 1.00
1,148	0.13%	SO2 to SO3 SCR (%) 1.00
0	0.00%	
3,180	0.25%	pSO3 (atm) 4.9087E-06
0.0	0.00%	pH2O (atm) 1.2236E-01
138,612	16.77%	Dewpoint Temperature (F) 271
860,000		
84.23%	84.23%	

AIR FLOW RATE CALCULATION

Boiler Heat Input Btu/Hr	Frg Rate Lb/Hr	Temp F	%H2Ogas	lb/hr	lb/lb	ACFM
8.8144E+09	1,056,163	80.0	12.00	10,836,218	0.0729	2,465,837
8.8144E+09	1,056,163	100.0	12.00	10,836,218	0.0729	2,508,215
8.8144E+09	1,056,163	90.0	12.00	10,836,218	0.0729	2,486,731
8.8144E+09	1,056,163	70.0	12.00	10,836,218	0.0729	2,443,971
8.8144E+09	1,056,163			10,836,218	0.0835	2,727,138

GAS FLOW RATE CALCULATION

Temp F	H2O Gas	lb/hr	lb/lb	ACFM
700.0	-0.00	11,836,661	-0.0329	5,466,836
350.0	12.00	11,836,661	-0.0329	3,835,474
345.0	12.00	11,836,661	-0.0329	3,807,186
330.0	12.00	11,836,661	-0.0315	3,706,466
53.0	0.000	11,836,661	-0.0161	2,867,000

(SCFM)

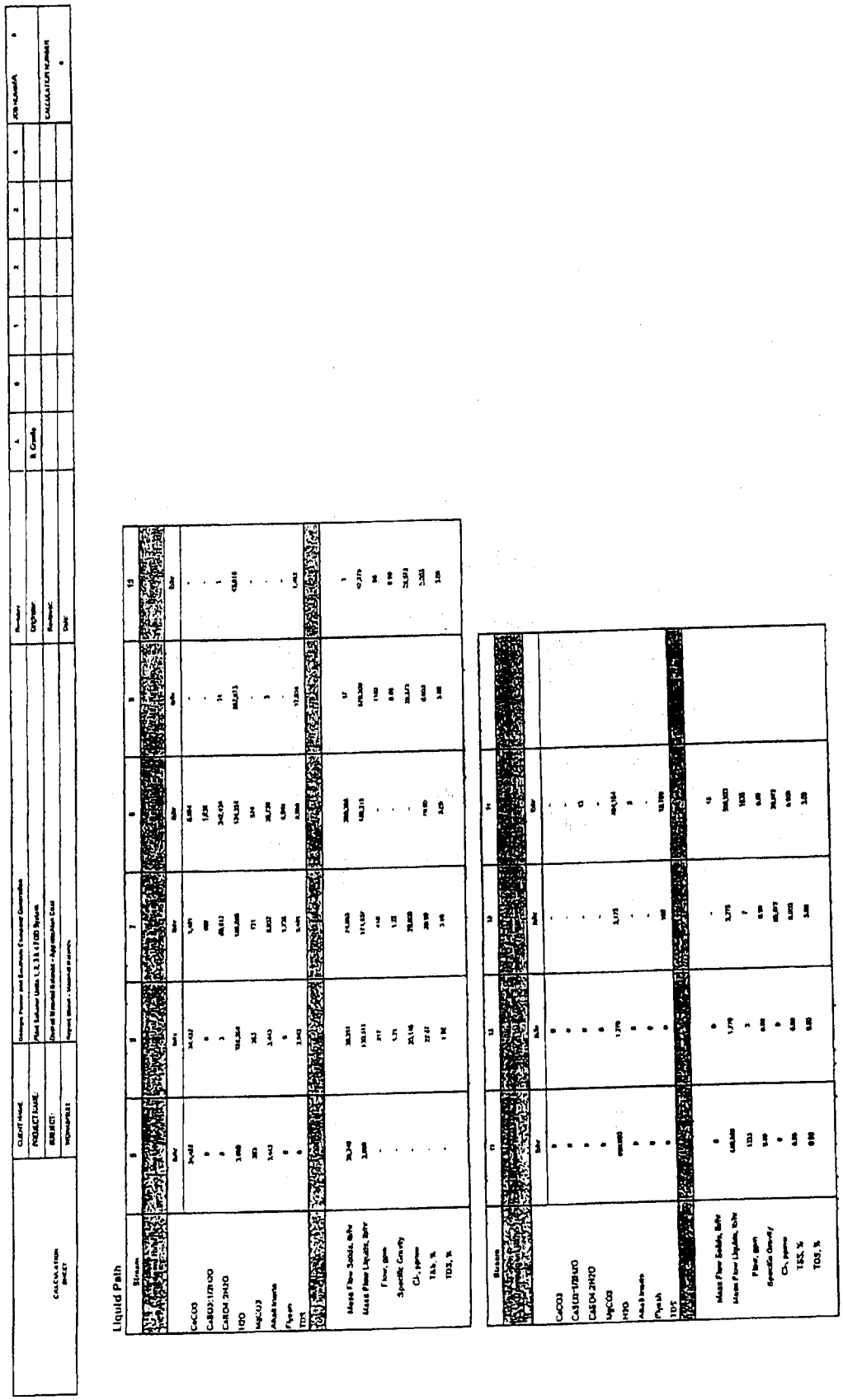
Florida Power & Light
Docket No. 070007-EI
Staff's Fourth Set of Interrogatories
Interrogatory No. 36
Attachment 1, Page 76 of 131

CALCULATION SHEET	CLIENT NAME:	Georgia Power and Southern Company Generation	Revision:	A	0	1	2	3	4	JOB NUMBER: 0
	PROJECT NAME:	Plant Scherer Units 1, 2, 3 & 4 FWD System	Originator:	B. Goudy						
	SUBJECT:	Overall Mercator Balance - Appalachian Coal	Approver:							CALCULATION NUMBER: 0
	WORKSHEET:	Report Sheet - Mercator Balance	Date:							

Gas Path

Stream		Ref.		1		2		3		4					
Air		112,340	2,312	139,340	2,312	139,000	2,300	840	15						
CO2		1,910,350	42,044	1,890,154	43,044	1,866,896	48,316	0	0						
HCl		1,700	35	1,300	35	0	0	0	0						
Hg		97	5	97	5	0	0	0	0						
H2O		888,891	33,830	868,581	33,897	1,230,177	67,720	1,290	70						
N2		3,714,000	270,834	7,711,841	273,541	7,704,543	270,816	33,300	1,300						
NH3		0	1	0	1	0	1	0	0						
SO2		300	10	104	10	304	10	0	0						
O2		704,000	34,830	704,000	34,830	400,674	20,830	11,000	340						
SO3		20,000	300	20,004	300	670	10	0	0						
SO3		000	7	000	7	370	4	0	0						
Total Dist Flow, lbs/															
Total Dist Flow, Dry															
Coal	700,000	0				0		0							
Ash	0	00,000		454		113		0							
Total Solids Flow	700,000	00,000		454		113		0							
Gas Flow, ACFM		3,000,000		3,710,101		3,000,000		1,300							
Mol. Wt.			29.0004		28.8002		28.2007		28.0177						
Temp, deg F		300		300		100		311							
Pressure, psia		13.0000		14.0004		14.4710		30.5040							

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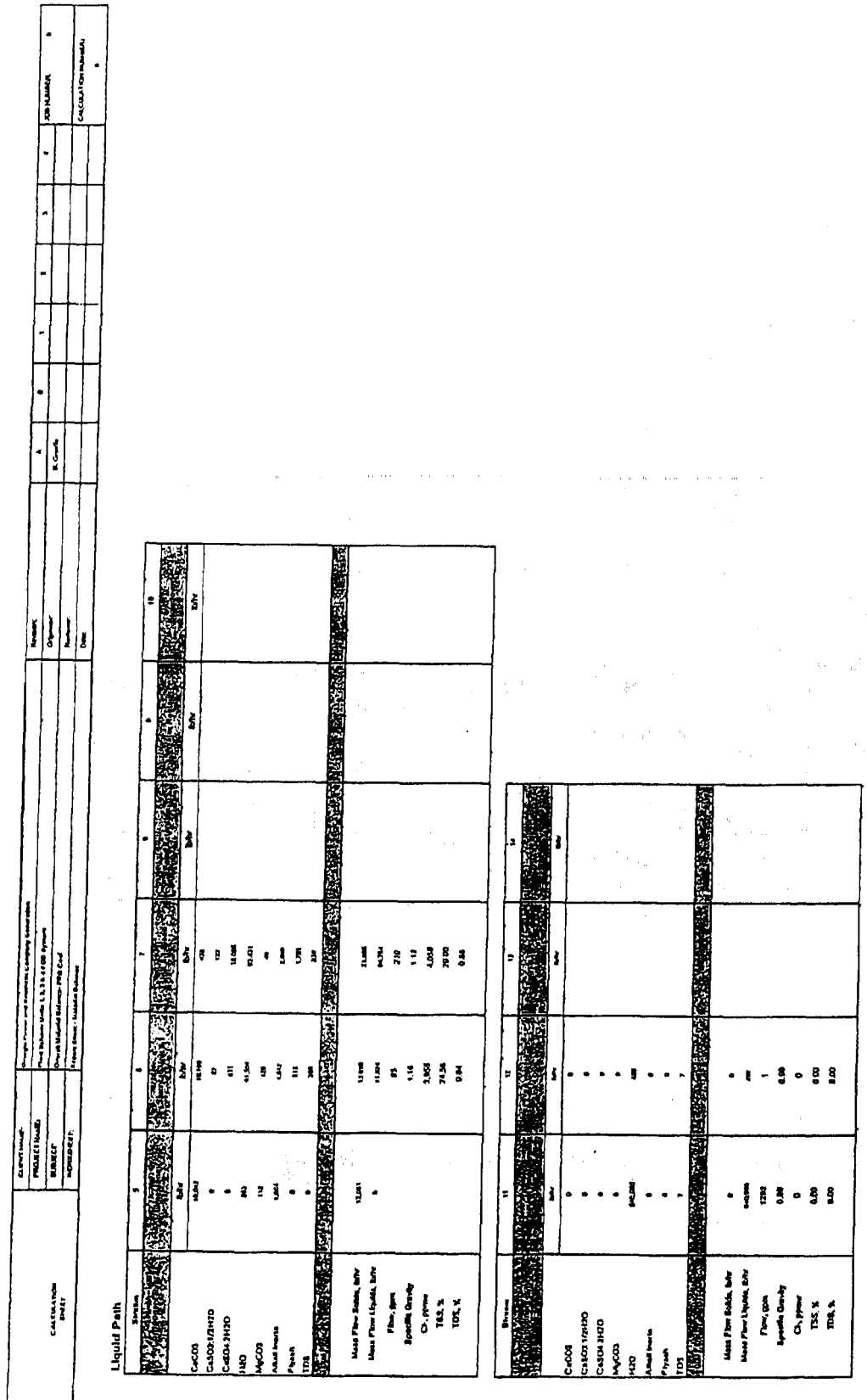


CALCULATION SHEET	CLIENT:	Georgia Power and Southern Company Consortium	Revision:	A	B	1	2	3	4	JOB NUMBER:
	PROJECT NAME:	Plant Scherer Units 1, 2, 3 & 4 FGD Systems	Originator:	B. Smith						
	SUBJECT:	Overall Material Balance - PRB Coal	Reviewer:							CALCULATION NUMBER:
	WORKSHEET:	Report Sheet - Material Balance	Date:							

Gas Path

Stream		Inlet		1		2		3		4					
Ar		134,999	3,374	134,943	3,370	136,188	3,404	136,123	3,343	188	5				
CO2		1,848,744	44,351	1,974,714	44,864	1,382,917	43,888	1,882,871	43,864	0	0				
HCl		111	3	111	3	0	0	0	0	0	0				
HF		61	3	61	3	0	0	0	0	0	0				
H2O		883,343	49,049	883,343	49,049	1,838,384	88,837	1,913,374	91,837	388	73				
N2		7,897,799	266,886	7,897,799	266,886	7,878,838	281,248	7,878,838	281,248	15,936	888				
NH3		0	0	0	0	0	0	0	0	0	0				
NOx		384	10	384	10	384	10	384	10	0	0				
O2		818,198	25,320	818,198	25,320	812,848	26,387	812,848	26,377	3,348	106				
SO2		0,198	94	0,198	94	134	2	134	2	0	0				
SO3		198	2	198	2	198	2	198	2	0	0				
Ca(OH)2	1,888,148	0				0		0		0					
Ash	0	98,134		484		113		113		0					
Total Solids Flow	1,888,148	98,134		484		113		113		0					
Gas Flow, ACFM		4,448,888		2,888,888		3,331,894		3,288,737		3,284					
Gas Vel.			38,8228		38,8845		28.8428		38.8438		28.8427				
Temp, deg F		338		383		138		138		388					
Pressure, psia		13.8728		14.8884		14.4728		14.4848		38.5828					

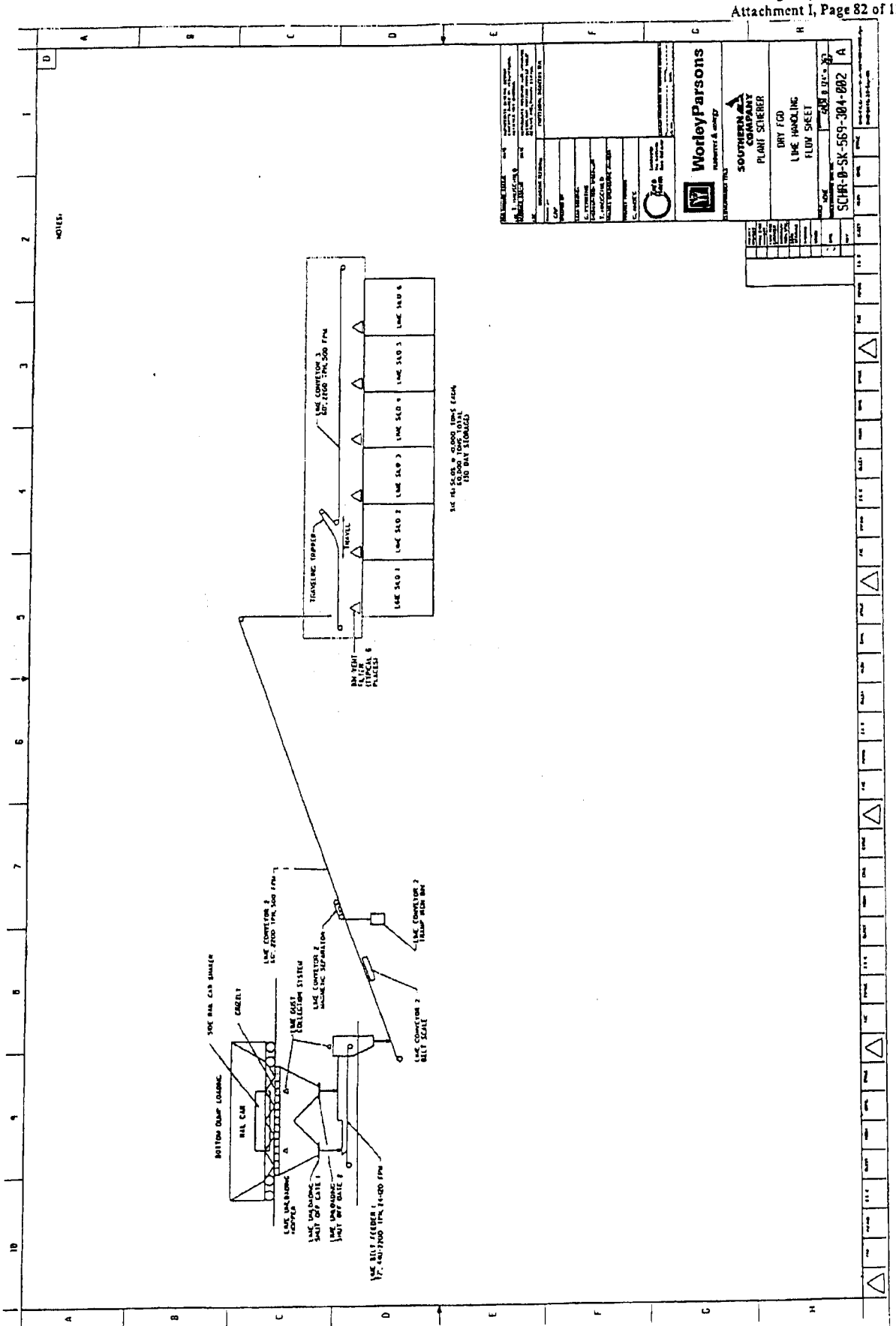
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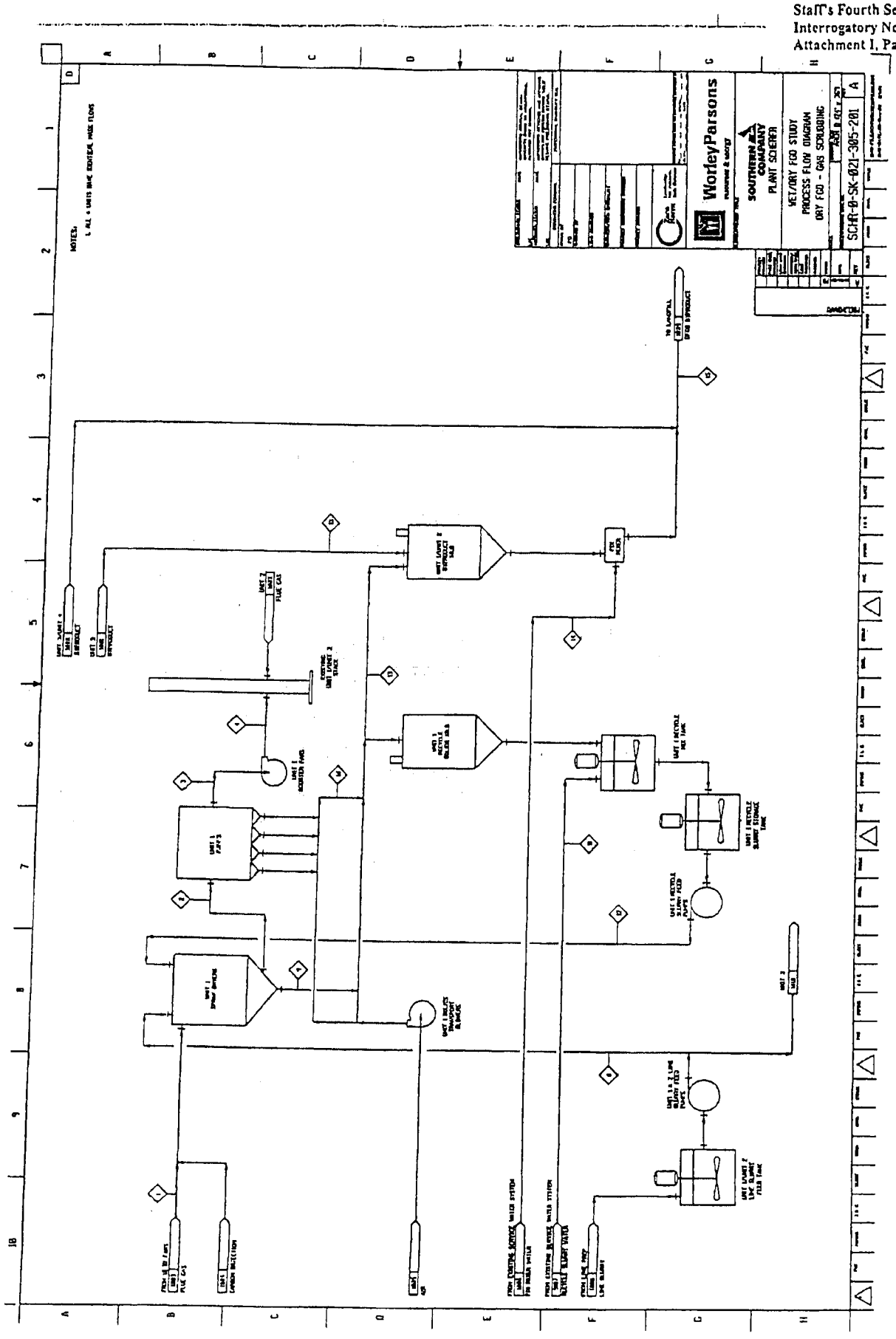


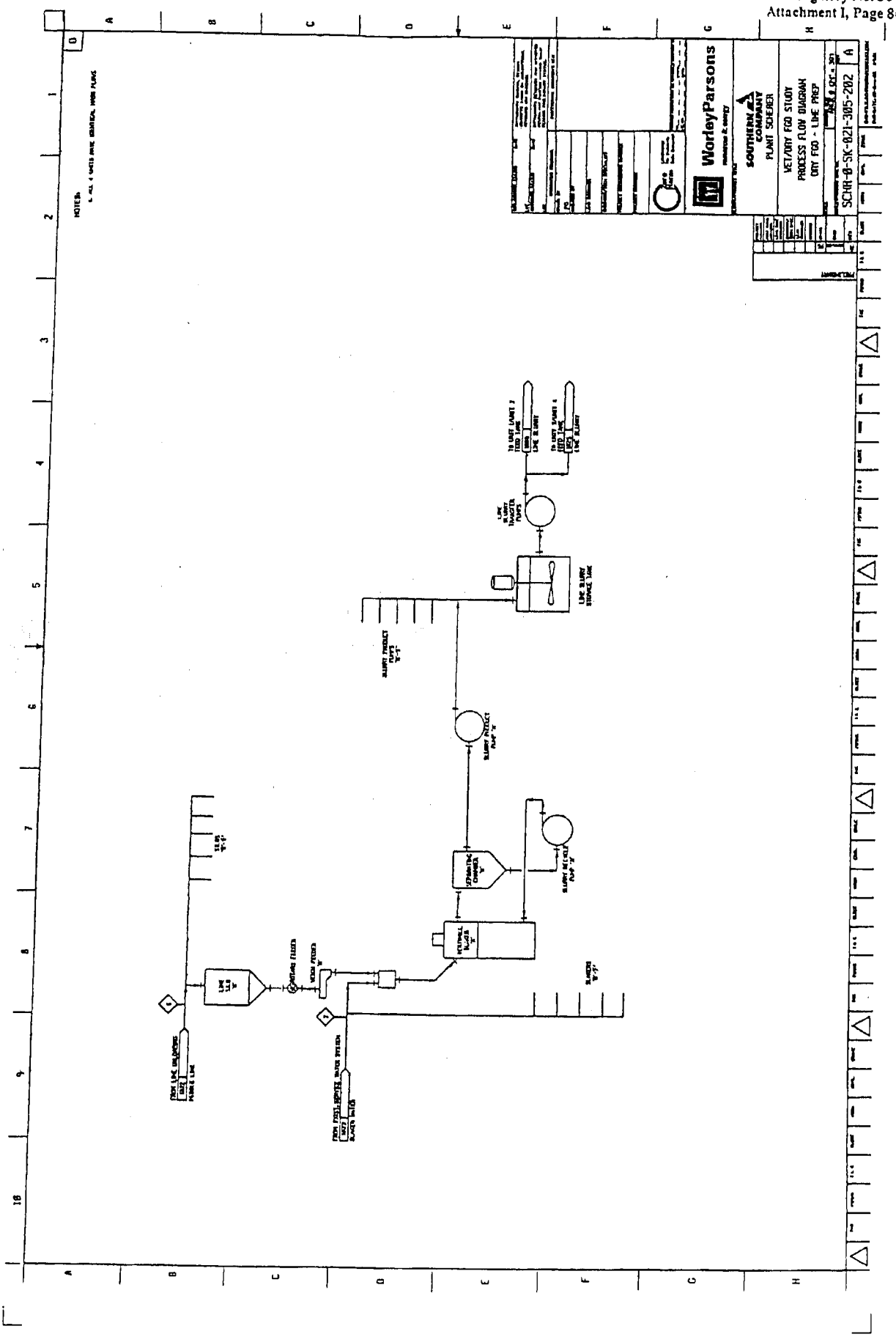
APPENDIX E

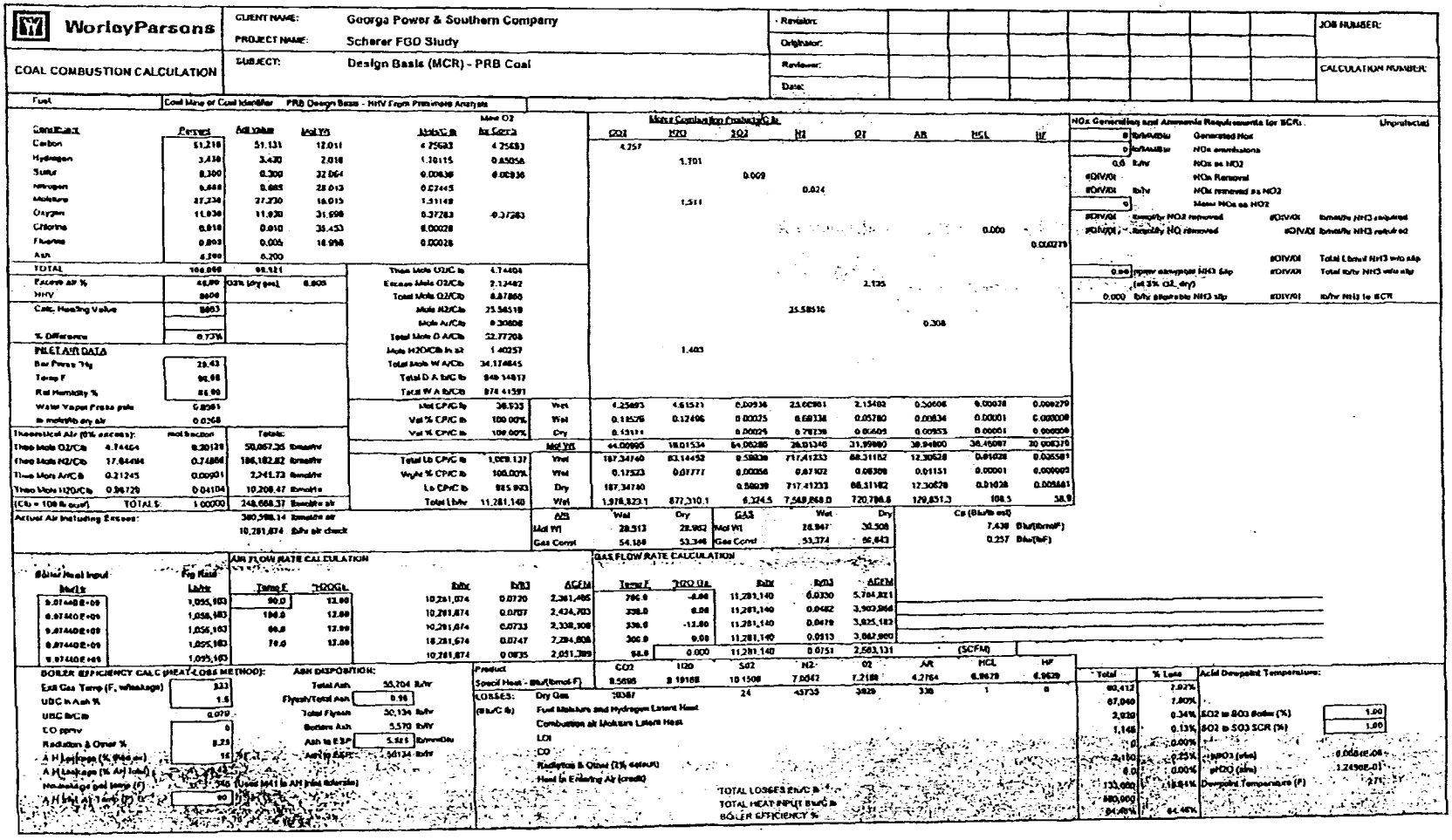
CONCEPTUAL PROCESS DESIGN – DRY FGD

- Lime Handling Flow Diagram
  SCHR-0-SK-569-304-002
- FGD Process Flow Diagram (2 shts)
  SCHR-0-SK-021-305-201
  SCHR-0-SK-021-305-202
- Combustion Calculations
- Material Balance


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
DRY FGD
LIME HANDLING
FLOW SHEET
SCHR-0-SK-569-304-002
A
NOTES:
TRAVELING TRIPPER
TRAVEL
RAIL CAR
BOTTOM DUMP LOADING
LIME UNLOADING HOPPER
LIME UNLOADING SHUT OFF GATE 1
LIME UNLOADING SHUT OFF GATE 2
LIME BELT FEEDER 1
LIME DUST COLLECTION SYSTEM
LIME CONVEYOR 2 BELT SCALE


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
WET/DRY FGD STUDY
PROCESS FLOW DIAGRAM
DRY FGD - GAS SCRUBBING
SCHR-0-SK-021-305-201
NOTES:
1. ALL 4 UNITS SHOWN, EXISTING, MASS FLOWS


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
VET/DRY FGD STUDY
PROCESS FLOW DIAGRAM
DRY FGD - LIME PREP
SCHR-0-SK-021-305-202



WorleyParsons

CLIENT NAME: Georgia Power & Southern Company
PROJECT NAME: Scherer FGD Study
SUBJECT: Design Basis (MCR) - PRB Coal

COAL COMBUSTION CALCULATION

Revision:
Originator:
Reviewer:
Date:

JOB NUMBER:
CALCULATION NUMBER:

Fuel: Coal Mine or Coal Identifier: PRB Design Basis - HHV From Proximate Analysis

Constituent	Percent	Act Value	Mol Wt	Moles/lb fuel	Mole O2 for Comb
Carbon	51.210	51.131	12.011	4.25683	4.25683
Hydrogen	3.430	3.430	2.016	1.70115	0.85058
Sulfur	0.300	0.300	32.064	0.00936	0.00936
Nitrogen	0.680	0.685	28.013	0.02445	
Moisture	27.230	27.230	18.015	1.51148	
Oxygen	11.030	11.030	31.998	0.37283	-0.37283
Chlorine	0.010	0.010	35.453	0.00028	
Fluorine	0.003	0.005	18.998	0.00026	
Ash	6.300	6.200			
TOTAL	100.000	99.121			
Excess air %	15.00	(O2% dry gas)	3.005		
HHV	8600				
Calc. Heating Value	8603				
% Difference	0.03%				

Theo Mole O2/C lb	4.74404	
Excess Mole O2/C lb	2.13482	
Total Mole O2/C lb	6.87886	
Mole N2/C lb	25.58519	
Mole Ar/C lb	0.30808	
Total Mole D A/C lb	32.77208	
Mole H2O/C lb in air	1.40257	
Total Mole W A/C lb	34.17464	
Total D A lb/C lb	949.14817	
Total W A lb/C lb	974.41591	

Mol CP/C lb	36.933	Wet	4.25683
Vol % CP/C lb	100.00%	Wet	0.16576
Vol % CP/C lb	100.00%	Dry	0.13111
		Mol Wt	44.00995
Total Lb CP/C lb	1,009.137	Wet	187.34760
Wgt% CP/C lb	100.00%	Wet	0.17523
Lb CP/C lb	925.993	Dry	187.34760
Total Lb/hr	11,281,140	Wet	1,978,323.1

	4.61521	0.00936	23.60981	2.13482	0.30808	0.00028	0.000270	
	0.12496	0.00025	0.69334	0.05780	0.00834	0.00001	0.000008	
		0.00024	0.78238	0.06605	0.00953	0.00001	0.000008	
	18.01534	64.06288	28.01348	31.99880	39.94800	36.46087	20.008376	
	83.14452	0.58838	717.41233	68.31182	12.30628	0.01028	0.005581	
	0.07771	0.00056	0.67102	0.06308	0.01151	0.00001	0.000005	
		0.58039	717.41233	68.31182	12.30628	0.01028	0.005581	
	877,310.1	6,324.5	7,549,868.0	720,786.6	129,851.3	108.5	58.9	

Actual Air Including Excess: 380,988.14 lbs/hr air
10,281,874 lbs/hr air check

	AIR Wet	AIR Dry	GAS Wet	GAS Dry	Cp (Btu/lb mol)	
Mol Wt	28.913	28.952	28.947	30.508	7.439	Btu/(lbmol-F)
Gas Const	54.168	53.346	53.374	50.843	0.257	Btu/lbF

NOx Generating and Ammonia Requirements for SCRs: Uncontrolled

0	lb/MMBtu	Generated NOx	
0	lb/MMBtu	NOx emissions	
0.6	lb/hr	NOx as NO2	
#DIV/0!		NOx Removal	
#DIV/0!	lb/hr	NOx removed as NO2	
0		Mass NOx as NO2	
#DIV/0!	lbmol/hr NO2 removed	#DIV/0!	lbmol/hr NH3 required
#DIV/0!	lbmol/hr NO removed	#DIV/0!	lbmol/hr NH3 reburned
		#DIV/0!	Total Lbmol NH3 into slip
0.00	ppmv ammonia NH3 slip (at 3% O2, dry)	#DIV/0!	Total lb/hr NH3 into slip
0.000	lb/hr ammonia NH3 slip	#DIV/0!	lb/hr NH3 to SCR

AMBIENT DATA

Bar Press "Hg	29.43
Temp F	90.00
Rel Humidity %	66.90
Water Vapor Press psia	0.8581
lb mol/lb dry air	0.0368

Theoretical Air (0% excess):	mol fraction	Totals:	
Theo Mole O2/C lb	4.74404	50,057.26	lbmol/hr
Theo Mole N2/C lb	17.84484	188,182.82	lbmol/hr
Theo Mole Ar/C lb	0.21245	2,241.73	lbmol/hr
Theo Mole H2O/C lb	0.36729	10,208.47	lbmol/hr
(Cb + 100 lb dust) TOTALS	1.00000	248,668.37	lbmol/hr air

Boiler Heat Input

Btu/hr	Pg Heat Lb/hr
9.87440E+09	1,095,163
9.87440E+09	1,095,163
9.87440E+09	1,095,163
9.87440E+09	1,095,163
9.87440E+09	1,095,163

AIR FLOW RATE CALCULATION

Temp F	H2OGr.	lb/hr	lb/ft3	ACFM
90.0	72.00	10,281,874	0.0720	2,381,485
190.0	72.00	10,281,874	0.0707	2,424,703
66.0	72.00	10,281,874	0.0733	2,338,308
70.0	72.00	10,281,874	0.0747	2,294,808
		10,281,874	0.0735	2,051,389

GAS FLOW RATE CALCULATION

Temp F	H2O Gr.	lb/hr	lb/ft3	ACFM
706.9	-0.00	11,281,140	0.0330	5,704,821
356.0	0.00	11,281,140	0.0482	3,903,966
336.0	-13.80	11,281,140	0.0478	3,925,183
306.9	9.00	11,281,140	0.0513	3,662,960
94.0	0.000	11,281,140	0.0751	2,503,131

(SCFM)

CO2	H2O	SO2	N2	O2	AR	HCL	HF
0.5698	0.19188	19.1508	7.0042	7.2188	4.2764	6.9679	6.9629

BOILER EFFICIENCY CALC (HEAT LOSS METHOD):

Exit Gas Temp (F, wet/sat.)	333	
UBC in Ash %	1.5	
UBC lb/C lb	0.079	
CO ppmv	0	
Radiation & Other %	0.25	
A H Leakage (% Air Flow)	15	
A H Leakage (% Air Inlet)	17.5	
Heat Loss (Lost Heat to Air Inlet Balance)	345	
A H Inlet Air Temp (F)	90	

ASH DISPOSITION:

Total Ash	55,704	lb/hr
Flyash/Total Ash	0.90	
Total Flyash	50,134	lb/hr
Bottom Ash	5,570	lb/hr
Ash to ESP	5.925	lb/mmBtu
Ash to ESP	1.50134	lb/hr

Product								
Specif Heat - Btu/(lbmol-F)		8.5698	8.19188	19.1508	7.0042	7.2188	4.2764	6.9679	6.9629
LOSSES: (Btu/C lb)	Dry Gas	10387			24	45739	3829	336	1	0
	Fuel Moisture and Hydrogen Latent Heat									
	Combustion air Moisture Latent Heat									
	LOI									
	CO									
	Radiation & Other (1% default)									
	Heat in Entering Air (credit)									

	Total	% Loss
	60,412	7.02%
	67,040	7.80%
	2,930	0.34%
	1,148	0.13%
	0	0.00%
	2,150	0.25%
	0.01	0.00%
	133,000	15.84%
TOTAL LOSSES Btu/C lb	860,000	
TOTAL HEAT INPUT Btu/C lb	84.06%	84.46%
BOILER EFFICIENCY %		

Acid Dewpoint Temperature:

SO2 to SO3 Boiler (%)	1.00	
SO2 to SO3 SCR (%)	1.00	
pH2O (atm)	1.2498E-01	
Dewpoint Temperature (F)	271	

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070007-Hearing Exhibit 000117

MATERIAL BALANCE - DRY FGD PROCESS w/ CAPP COAL
Scherer Wet/Dry FGD Study

Stream -	(Ref)	1	2	3	4	5
Flue Gas	Flue Gas	Flue Gas	Flue Gas	Flue Gas	Flue Gas	(Not
	from AH	to Spray	from Spray	from	to Stack	Used)
	to ESP	Absorber	Absorber	Baghouse		
		(inc. ACI)				
Total gas, lb/hr	10,087,070	10,689,127	11,307,064	11,140,265	11,140,265	
Total (Gas), Dry	10,004,471	10,094,471	10,062,757	10,081,004	10,081,004	
Flow, ACFM	3,670,518	3,650,605	3,052,674	3,082,530	3,024,608	
Flow, SCFM	2,348,940	2,348,940	2,518,706	2,518,608	2,518,608	
Temp, °F	330	350	107	162	167	
Pressure, in w.c.	-12.0	0.0	-3.0	-10.0	0.5	
Pressure, psia	14.02	14.46	14.35	14.09	14.47	
Density, lb/ft3	0.0485	0.0488	0.0608	0.0602	0.0602	
Part, lb/MMBtu	0.803	0.227	18.368	0.015	0.015	
SO2, ppmwv	910.1	910.1	66.7	42.5	42.5	
SO2, lb/MMBtu	2.341	2.341	0.18	0.12	0.12	

Stream -	6	7	8	9	10	11	12	13	14	15
Solid/Liquid	Lime Feed	Slaker	Lime	Absorber	Baghouse	Recycle	Recycle	Total	Pin	Total
	to	Water	Slurry to	Solids	Solids	Water	Slurry to	Solid	Mixer	to
	Slaker*	Feed*	Atomizer	Catch	Catch	Feed	Atomizer	Product	Water**	Landfill*
Component										
CaO, lb/hr	148,461	0	0	0	0	0	0	0	0	0
Ca(OH)2, lb/hr	0	0	48,378	2,611	25,278	0	16,437	11,864	0	46,656
Flyash, lb/hr	0	0	0	495	4,455	0	2,897	2,056	0	8,222
Other, lb/hr	16,273	0	4,068	15,214	138,813	0	88,962	63,129	0	252,514
TSS, lb/hr	162,735	0	52,446	18,520	168,546	0	108,295	76,848	0	307,393
H2O, lb/hr	0	676,404	157,338	378	3,399	322,678	324,886	1,568	13,941	34,155
Total, lb/hr	162,735	676,404	209,785	18,898	169,945	322,678	433,182	78,416	13,941	341,547
Flow, GPM		1351	383	-	-	645	743	-	28	-
Specific Gravity		1.000	1.155	-	-	1.000	1.165	-	1.000	-
Temp, °F		Ambient	100 - 150	167	162	Ambient	Ambient	162	Ambient	Ambient
pH			10 - 12.5	-	-		7 - 8	-		-
TSS, %	100	0	25.00	98	98	0	25	98	0	90
Max. Flow, GPM	-	-	-	-	-		-	-	-	-

* 4 Units * 4 Units ** 2 Units * 4 Units

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MATERIAL BALANCE - DRY FGD PROCESS w/ PRB COAL
Scherer Wet/Dry FGD Study

Stream - Flue Gas	(Ref) Flue Gas from AH to ESP	1 Flue Gas to Spray Absorber (inc. ACI)	2 Flue Gas from Spray Absorber	3 Flue Gas from Baghouse	4 Flue Gas to Stack	5 (Not Used)
Total gas, lb/hr	11,281,140	11,283,224	11,855,778	11,780,010	11,780,010	
Total (Gas), Dry	10,403,830	10,403,830	10,394,962	10,394,750	10,394,750	
Flow, ACFM	3,925,211	3,903,917	3,297,102	3,329,730	3,267,155	
Flow, SCFM	2,511,930	2,511,930	2,692,516	2,692,491	2,692,491	
Temp, °F	330	350	174	169	173	
Pressure, in.w.c.	-12.0	0.0	-3.0	-10.0	0.5	
Pressure, psia	14.02	14.46	14.35	14.09	14.47	
Density, lb/ft3	0.0479	0.0482	0.0595	0.0590	0.0590	
Part. lb/MMBtu	5.525	0.230	8.341	0.015	0.015	
SO2, ppmwv	253.3	253.3	23.7	17.1	17.1	
SO2, lb/MMBtu	0.697	0.697	0.070	0.050	0.050	

Stream - Solid/Liquid	6 Lime Feed to Slaker*	7 Slaker Water Feed*	8 Lime Slurry to Atomizer	9 Absorber Solids Catch	10 Baghouse Solids Catch	11 Recycle Water Feed	12 Recycle Slurry to Atomizer	13 Total Solid Product	14 Pin Mixer Water**	15 Total to Landfill*
Component										
CaO, lb/hr	41,394	0	0	0	0	0	0	0	0	0
Ca(OH)2, lb/hr	0	0	13,673	1,237	11,112	0	8,976	3,388	0	13,552
Flyash, lb/hr	0	0	0	760	8,824	0	5,512	2,081	0	8,322
Other, lb/hr	4,599	0	1,150	8,414	57,610	0	46,541	17,567	0	70,268
TSS, lb/hr	45,993	0	14,823	8,410	75,556	0	61,029	23,035	0	92,142
H2O, lb/hr	0	250,462	59,291	172	1,542	448,305	447,549	470	4,179	10,238
Total, lb/hr	45,993	250,462	74,114	8,582	77,098	448,305	508,578	23,506	4,179	102,380
Flow, GPM		500	133	-	-	893	947	-	8	-
Specific Gravity		1.000	1.117	-	-	1.000	1.073	-	1.000	-
Temp, °F		Ambient	100 - 150	174	169	Ambient	Ambient	169	Ambient	Ambient
pH		0	10 - 12.5	-	-		7 - 8	-		-
TSS, %	100	0	20	98	98	0	12	98	0	90
Max. Flow, GPM	-	0	-	-	-		-	-	-	-

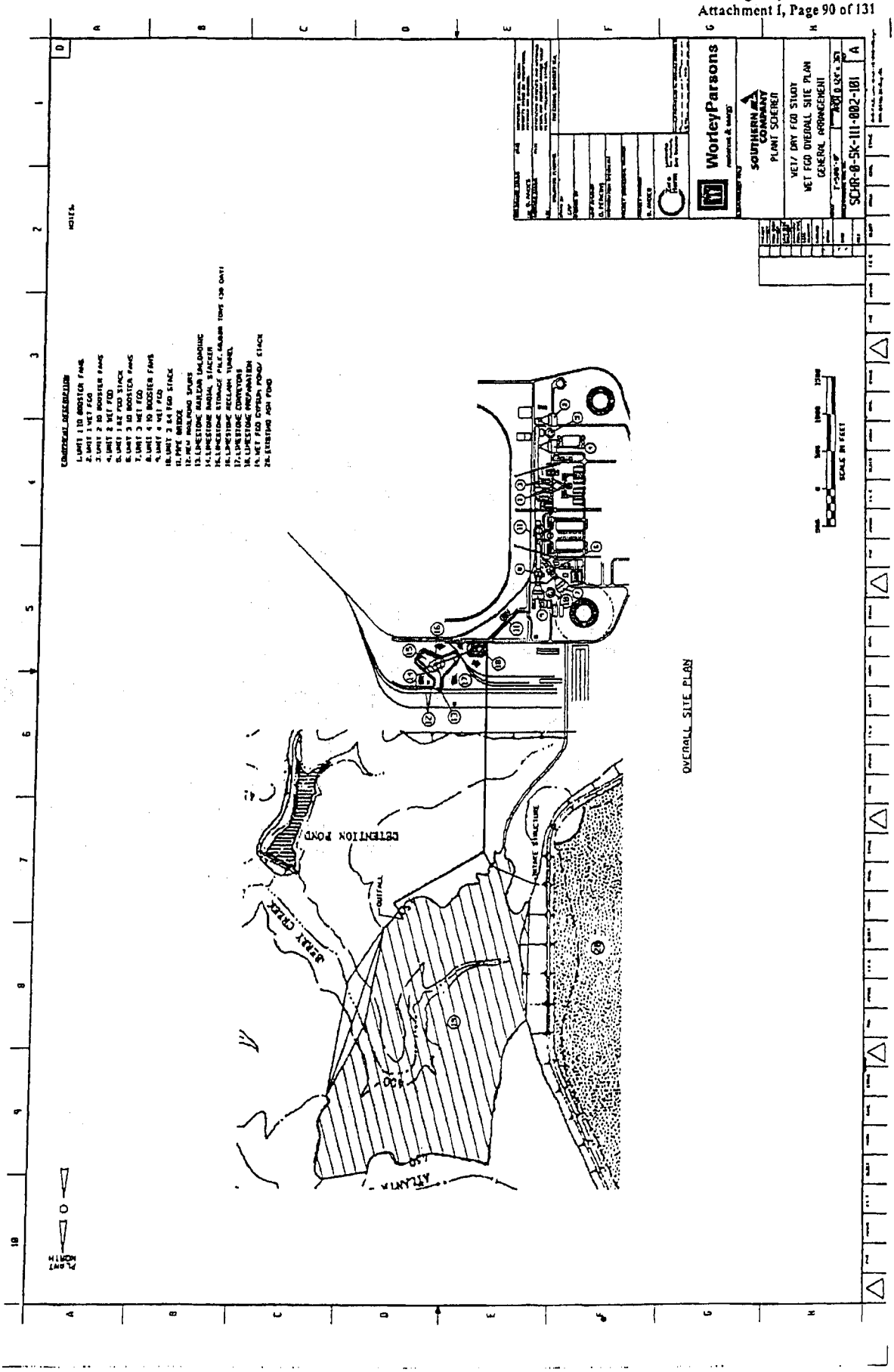
* 4 Units * 4 Units ** 2 Units * 4 Units

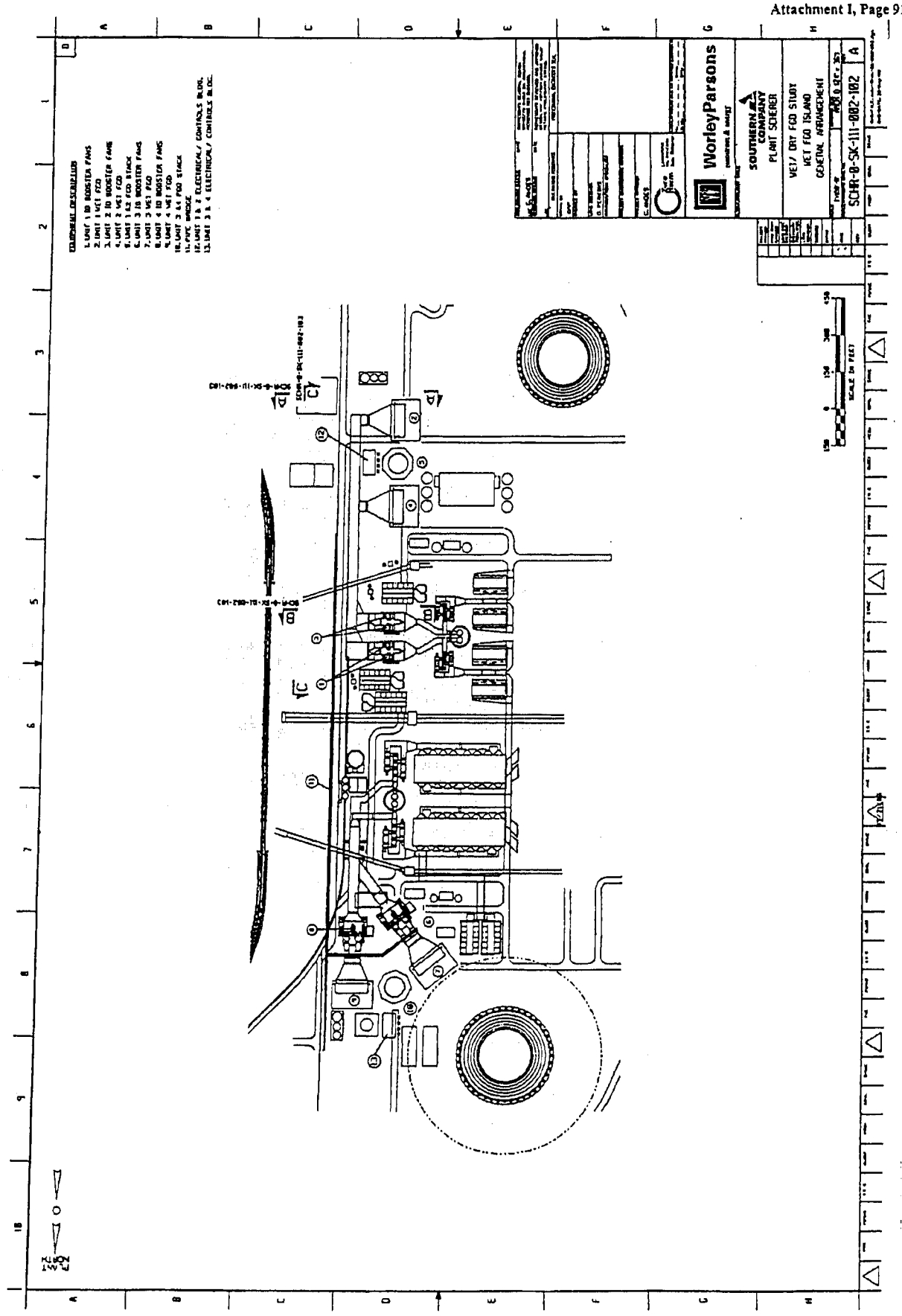
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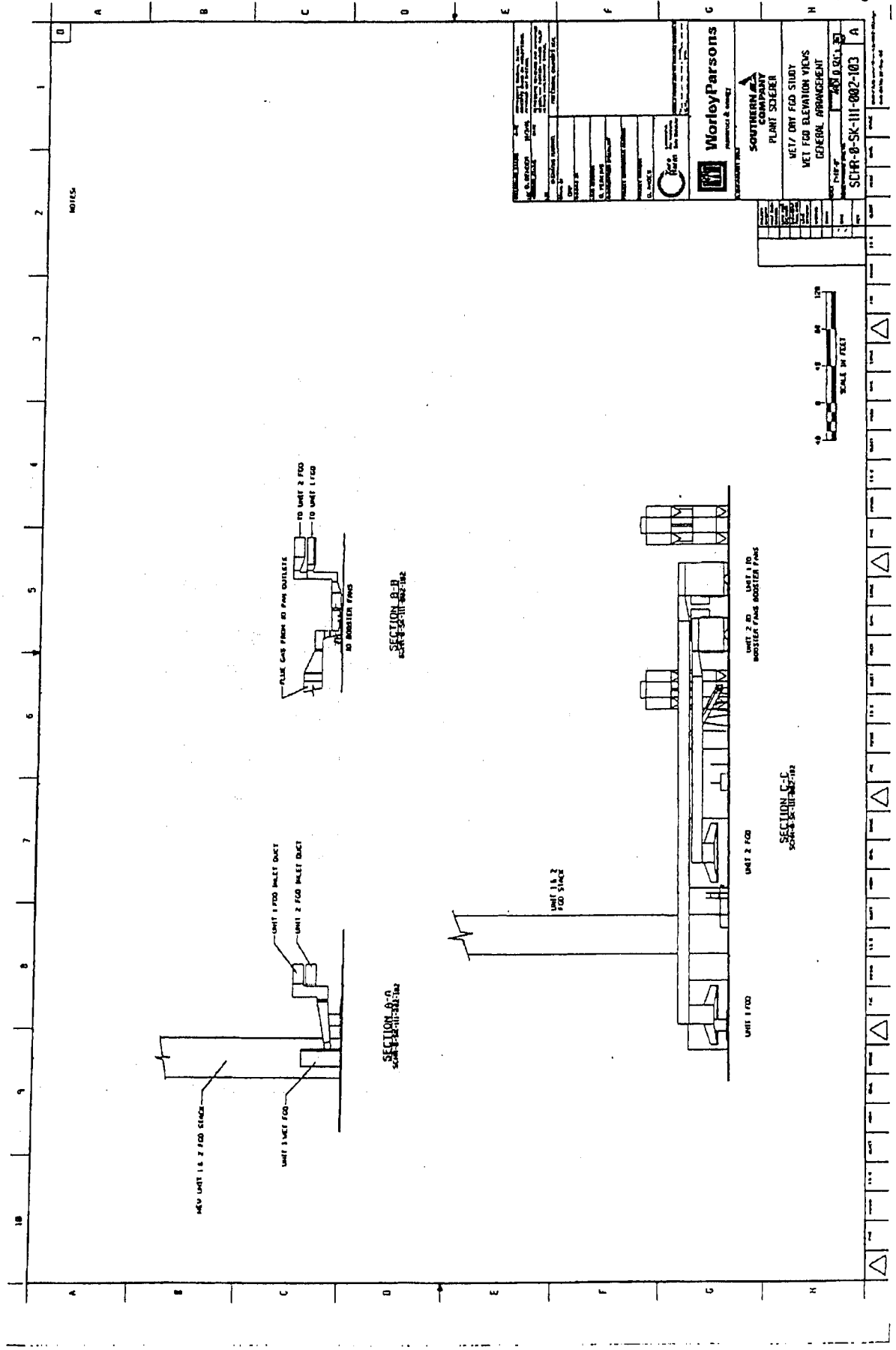
APPENDIX F

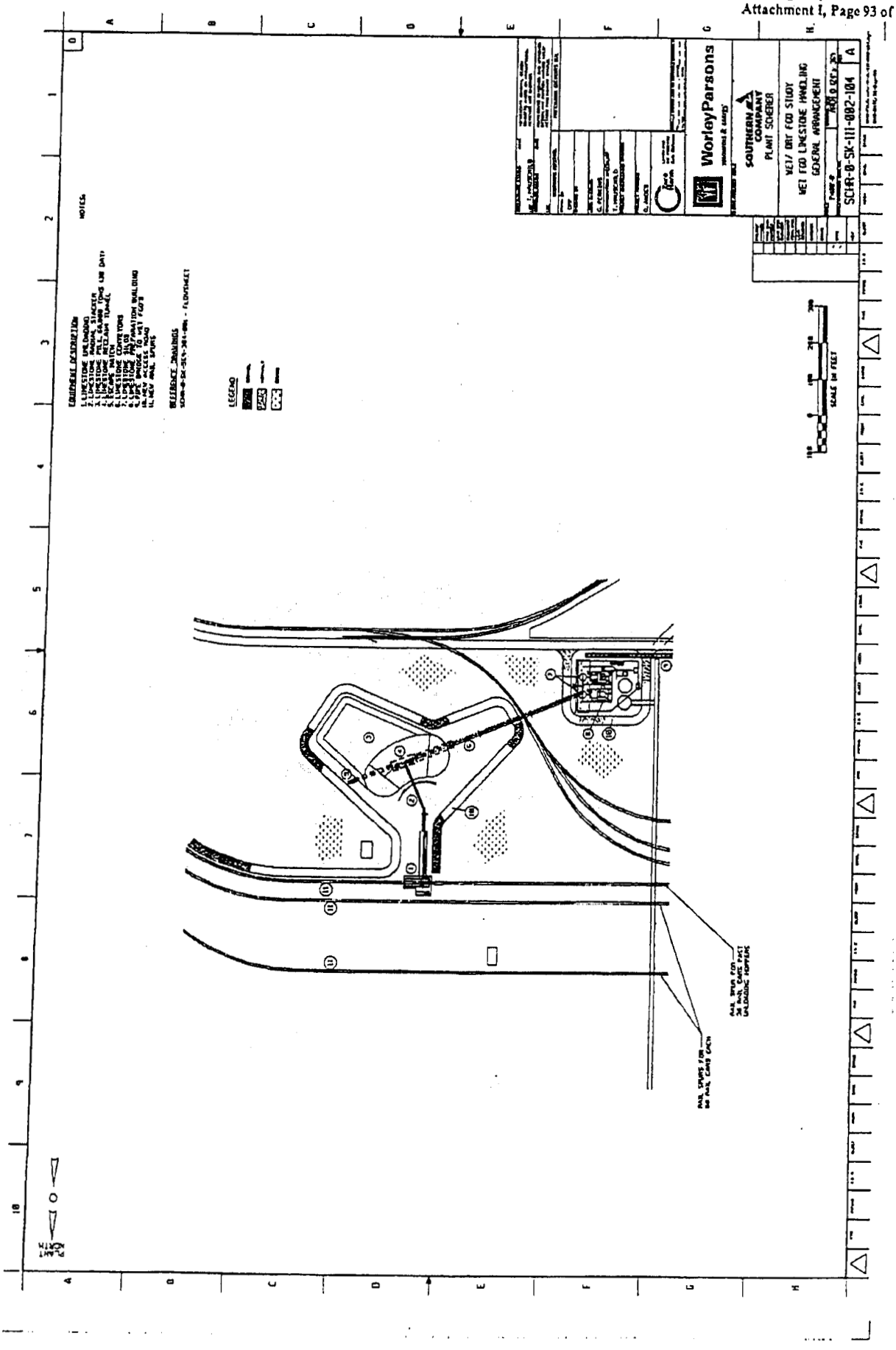
GENERAL ARRANGEMENTS – WET FGD

SCHR-0-SK-111-002-101
SCHR-0-SK-111-002-102
SCHR-0-SK-111-002-103
SCHR-0-SK-111-002-104


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
VERT DRY FGD STUDY
WET FGD OVERALL SITE PLAN
GENERAL ARRANGEMENT
SCHR-0-SK-111-002-101
OVERALL SITE PLAN
SCALE IN FEET
DETENTION POND
OUTFALL
ROUTE STRUCTURE
JERKY CREEK
ATLANTA


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
WET/ DRY FGD STUDY
WET FGD ISLAND
GENERAL ARRANGEMENT
SCHR-0-SK-111-0002-102

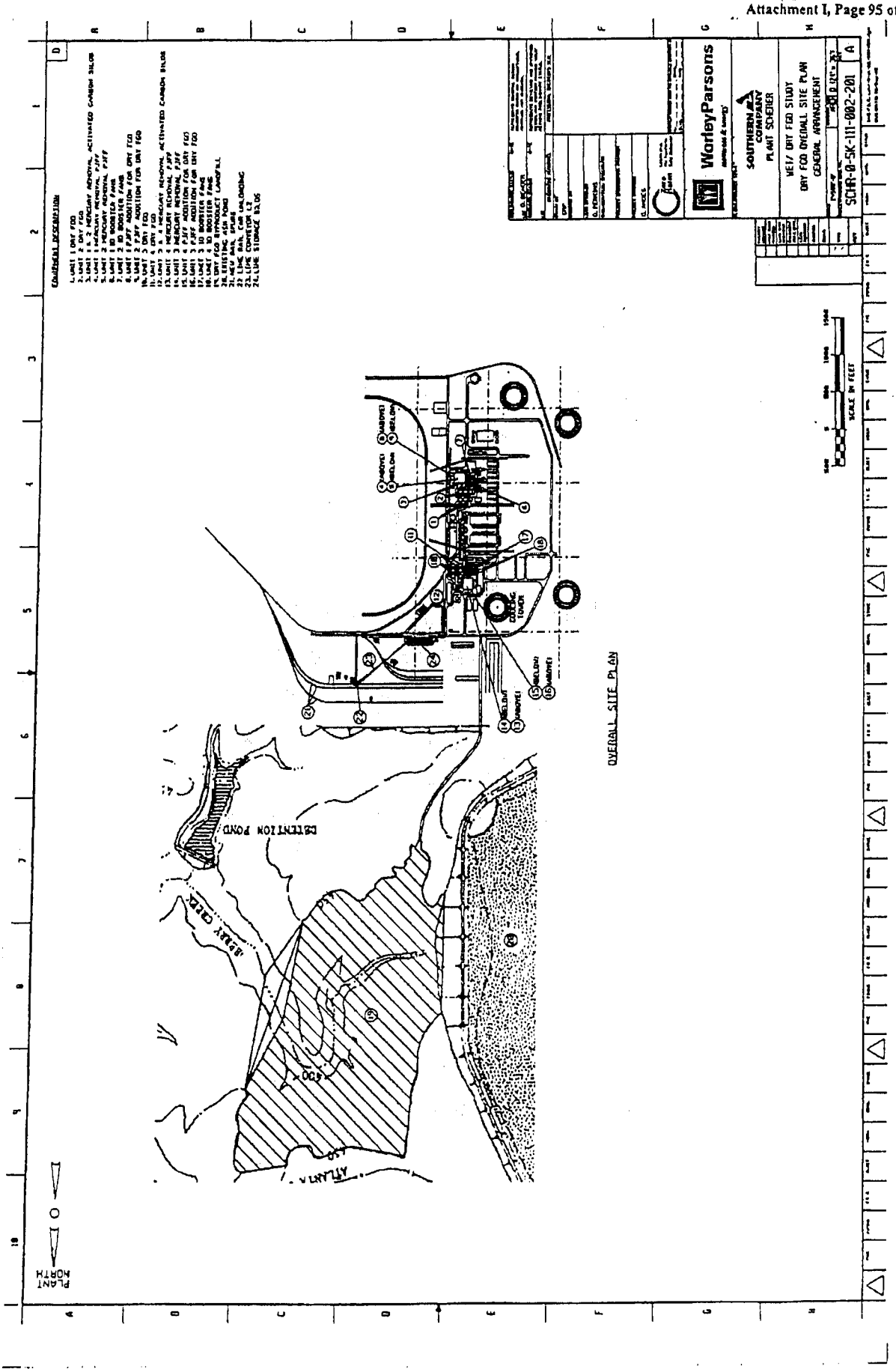

WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
WET/ DRY FGD STUDY
WET FGD ELEVATION VIEWS
GENERAL ARRANGEMENT
SCPA-0-SK-111-002-103
SECTION B-B
SECTION C-C
SECTION D-D
UNIT 2 FGD
UNIT 1 FGD
UNIT 1 & 2 FGD STACK
UNIT 1 FGD INLET DUCT
UNIT 2 FGD INLET DUCT
UNIT 1 WET FGD
NEW UNIT 1 & 2 FGD STACK
FLUE GAS FROM BY PASS OUTLETS
TO UNIT 2 FGD
TO UNIT 1 FGD
BY BOOSTER FANS
UNIT 2 BY BOOSTER FANS
UNIT 1 BY BOOSTER FANS
SCALE IN FEET

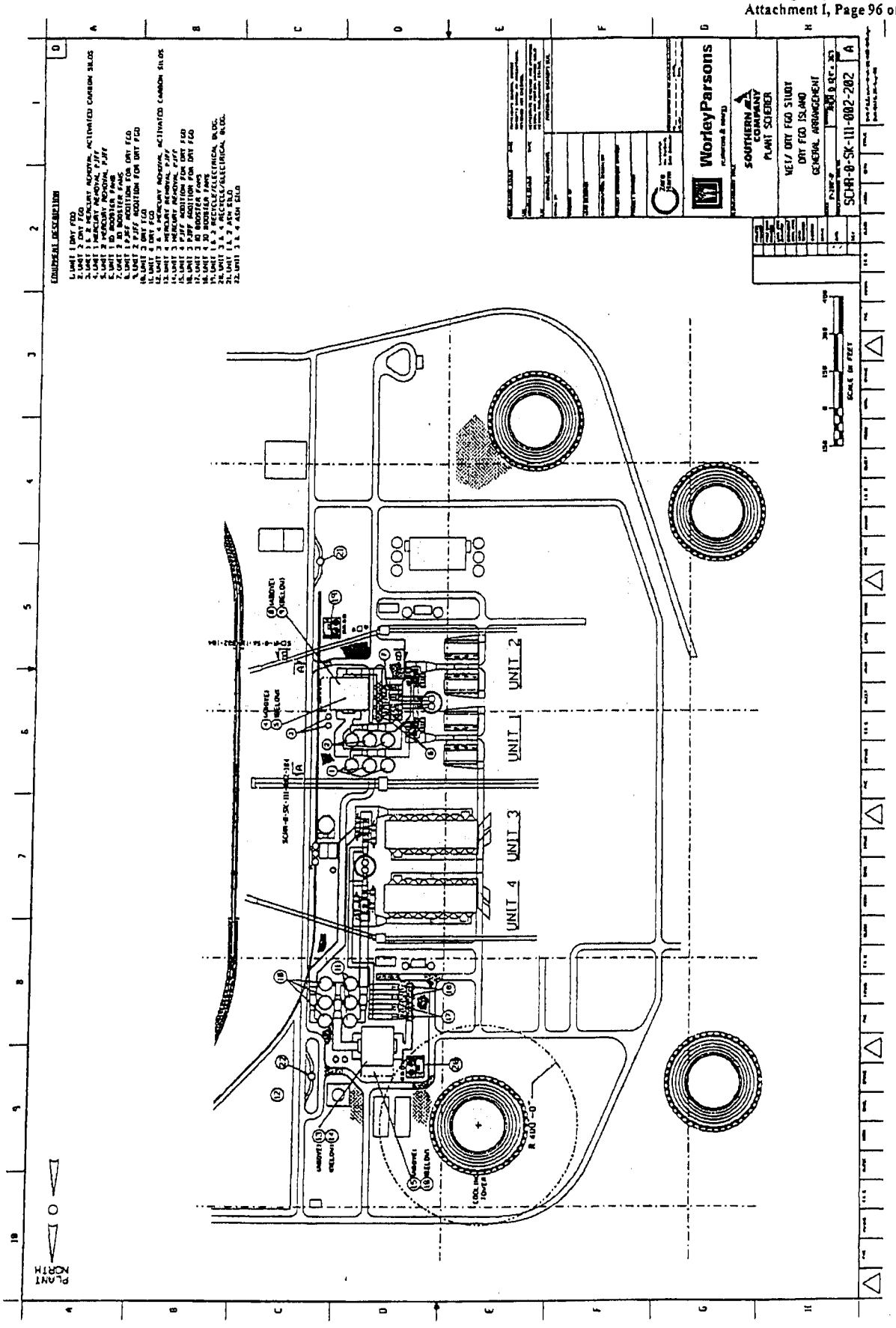

WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
WET/ DRY FGD STUDY
WET FGD LIMESTONE HANDLING
GENERAL ARRANGEMENT
SCHR-0-SK-111-002-104
A
NOTES
LEGEND
SCALE IN FEET

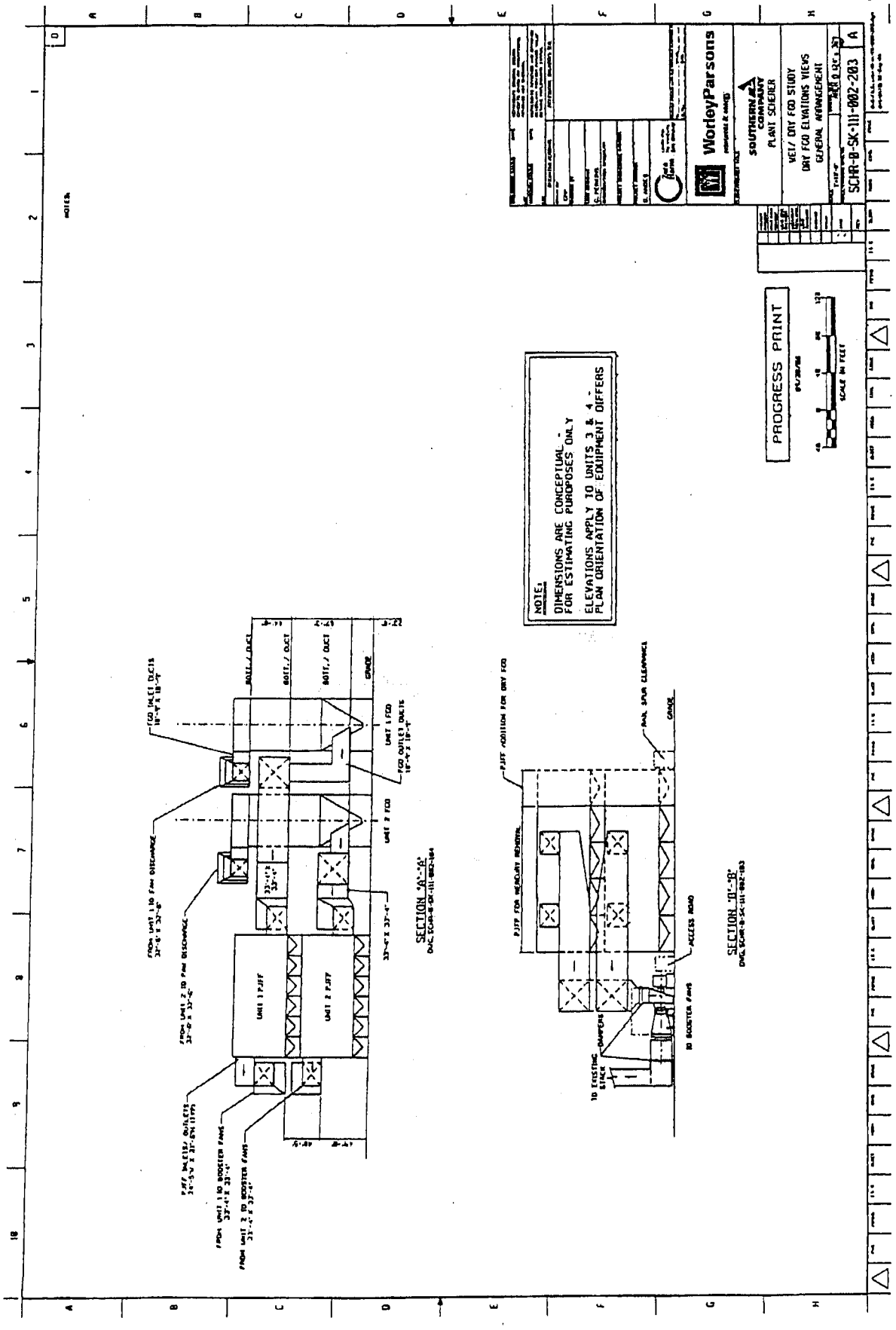
APPENDIX G

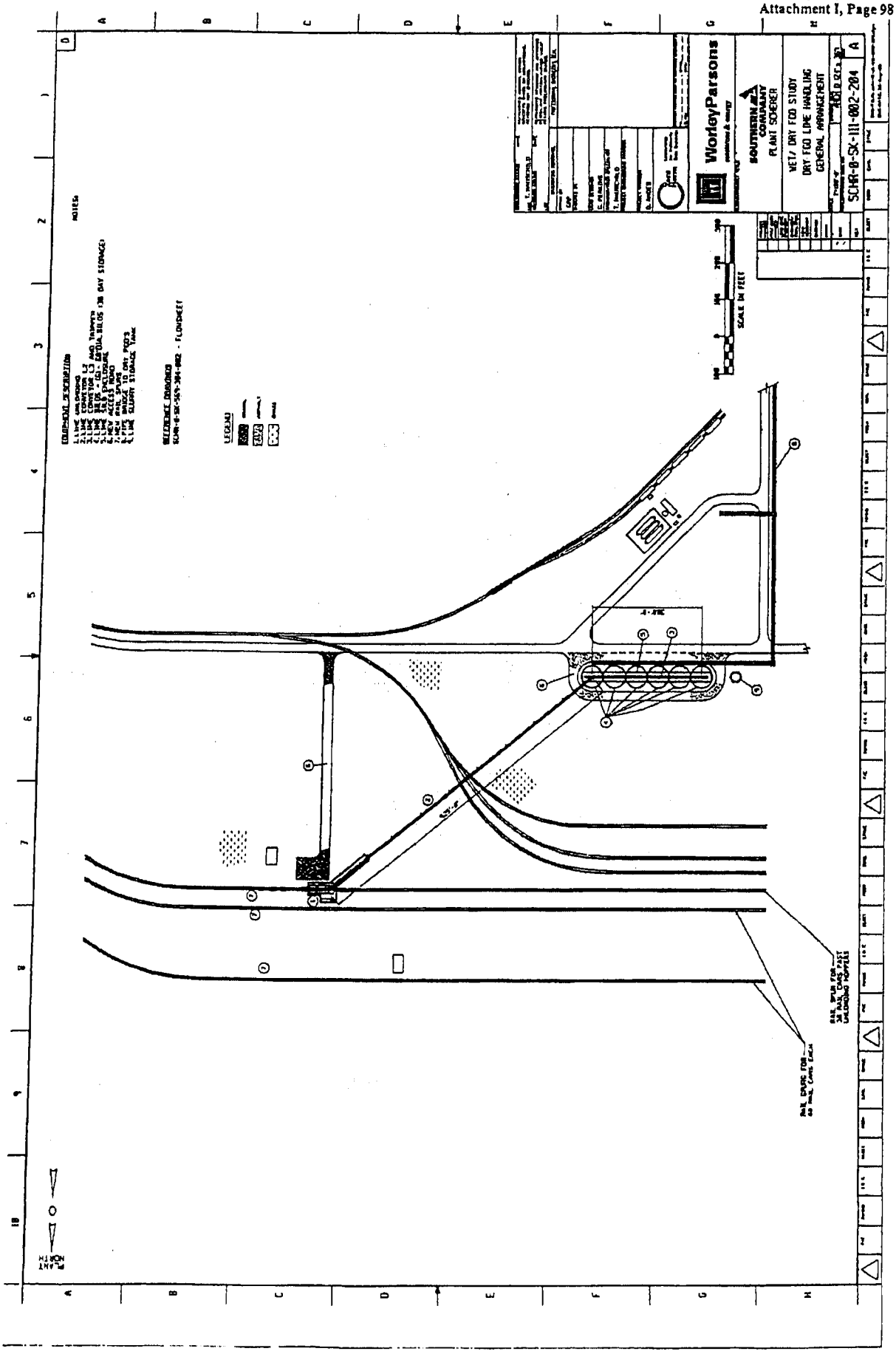
GENERAL ARRANGEMENTS – DRY FGD

SCHR-0-SK-111-002-201
SCHR-0-SK-111-002-202
SCHR-0-SK-111-002-203
SCHR-0-SK-111-002-204


WorleyParsons
SOUTHERN ALLIANCE COMPANY
PLANT SCHERER
WET/ DRY FGD STUDY
DRY FGD OVERALL SITE PLAN
GENERAL ARRANGEMENT
SCHR-0-SK-111-002-201
OVERALL SITE PLAN
SCALE IN FEET
SETTLING POND
SPARR CREEK
PLANT NORTH


EQUIPMENT DESCRIPTION
1. UNIT 1 DRY FGD
2. UNIT 2 DRY FGD
3. UNIT 1 & 2 MERCURY REMOVAL ACTIVATED CARBON SILOS
4. UNIT 1 MERCURY REMOVAL PJFF
5. UNIT 2 MERCURY REMOVAL PJFF
6. UNIT 1 ID BOOSTER FANS
7. UNIT 2 ID BOOSTER FANS
8. UNIT 1 PJFF ADDITION FOR DRY FGD
9. UNIT 2 PJFF ADDITION FOR DRY FGD
10. UNIT 3 DRY FGD
11. UNIT 4 DRY FGD
12. UNIT 3 & 4 MERCURY REMOVAL ACTIVATED CARBON SILOS
13. UNIT 4 MERCURY REMOVAL PJFF
14. UNIT 3 MERCURY REMOVAL PJFF
15. UNIT 3 PJFF ADDITION FOR DRY FGD
16. UNIT 4 PJFF ADDITION FOR DRY FGD
17. UNIT 3 ID BOOSTER FANS
18. UNIT 4 ID BOOSTER FANS
19. UNIT 1 & 2 RECYCLE/ELECTRICAL BLDG.
20. UNIT 3 & 4 RECYCLE/ELECTRICAL BLDG.
21. UNIT 1 & 2 ASH SILO
22. UNIT 3 & 4 ASH SILO
WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
KEY CITY FGD STUDY
DRY FGD ISLAND
GENERAL ARRANGEMENT
SCAR-0-SK-111-002-202
UNIT 1
UNIT 2
UNIT 3
UNIT 4
R 400'-0"
PLANT NORTH
SCALE IN FEET


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
WET/ DRY FGD STUDY
DRY FGD ELEVATIONS VIEWS
GENERAL ARRANGEMENT
SCHR-B-SK-111-002-203
NOTE:
DIMENSIONS ARE CONCEPTUAL -
FOR ESTIMATING PURPOSES ONLY
ELEVATIONS APPLY TO UNITS 3 & 4 -
PLAN ORIENTATION OF EQUIPMENT DIFFERS
PROGRESS PRINT
SECTION "A"-"A"
SECTION "B"-"B"
UNIT 1 FGD
UNIT 2 FGD
UNIT 1 PJFF
UNIT 2 PJFF
GRADE
ACCESS ROAD


WorleyParsons
SOUTHERN COMPANY
PLANT SCHERER
WET/ DRY FGD STUDY
DRY FGD LIME HANDLING
GENERAL ARRANGEMENT
SCHR-0-SK-111-0002-204
SCALE IN FEET
NOTES:
LEGEND:

APPENDIX H

LIFE CYCLE COST SPREADSHEETS – WET FGD

Table H-1
Table H-2

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SCHERER 1-4 WET FGD FACILITY
Life Cycle Cost Calculation / Bituminous Coal
TABLE H-1

[redacted]

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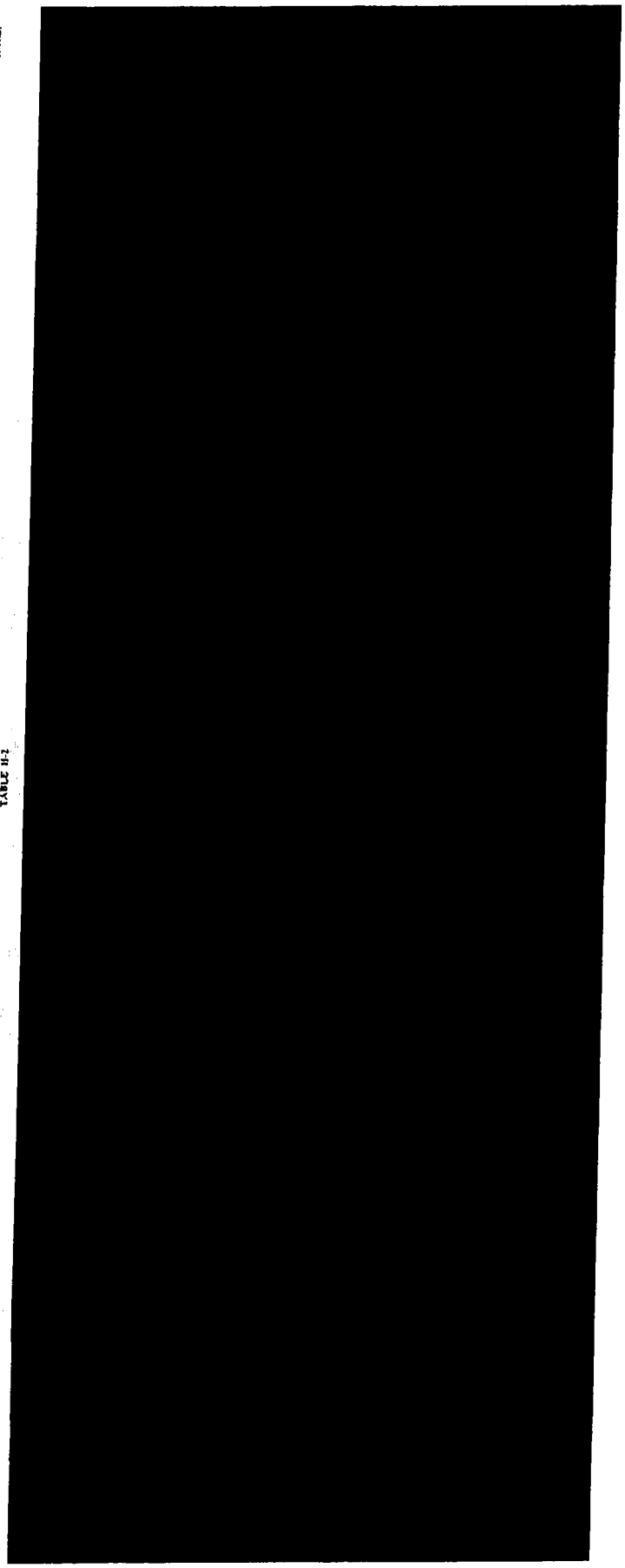
SCHERER 1-4 WET FGD FACILITY
LifeCycle Cost Calculation / Bituminous Coal
TABLE 11-1

[redacted]

070007-Hearing Exhibit 000133

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SCHERER 1-4 WET FGD FACILITY
LifeCycle Cost Calculation / PWR Cost
TABLE 11-2



CONFIDENTIAL

11/2/06

SCHERER 1-4 WET FGD FACILITY
LifeCycle Cost Calculation / FIB Cost
TABLE II-2

[redacted]

APPENDIX I

LIFE CYCLE COST SPREADSHEETS – DRY FGD

Table I-1
Table I-2

CONFIDENTIAL

Florida Power & Light
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Attachment I, Page 105 of 131

SCHERER 1-4 DRY FCD FACILITY
LifeCycle Coal Calculations / Bituminous Coal
TABLE 1-1

[redacted]

CONFIDENTIAL

[redacted]

SCHERER 1-4 DRY FGD FACILITY
LifeCycle Cost Calculation / Bituminous Coal
TABLE 1-1

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SCHERER 1-4 DRY FGD FACILITY
LifeCycle Cost Calculation / PRB Coal
TABLE 1-2

[redacted]

[redacted]

SCHERER 1-4 DRY FGD FACILITY
Life-Cycle Cost Calculation / PRB Coal
TABLE 1-1

APPENDIX J

BASIS OF THE CAPITAL COST ESTIMATES

WorleyParsons
resources & energy

Estimate Basis
Southern Company – Plant Scherer (4x900 MW)
Wet vs. Dry FGD Study

Introduction

WorleyParsons has been requested by Southern Company to prepare conceptual cost estimates to evaluate wet and dry flue gas de-sulfurization (FGD) technologies at Plant Scherer near Juliette, GA.

The estimates provide conceptual costs for engineering, procurement, and construction for the project. The estimates are based on brief descriptions and general arrangements. The estimate accuracy is - 25%/+35%. The pricing is based on the WorleyParsons pricing database and supplemented with quotes. The estimates were developed to evaluate the costs and benefits of the two technologies and are not intended to represent the complete project cost. A detailed cost estimate of the total scope must be prepared to establish costs suitable for budgeting.

Scope of Work

The wet FGD estimate is based on using the Advatech FGD technology. The scope includes new chimneys, new booster ID fans, ductwork, wet FGD absorbers, new rail spurs, limestone unloading system, limestone handling system, limestone preparation system, field-erected tanks, gypsum disposal pond, additional DCS, start-up transformers, unit auxiliary transformers, foundations, sitework, utility piping, and bulk electrical. Engineered buildings are included for the limestone preparation system, and the electrical/control equipment.

The dry FGD estimate is based on current spray dryer absorber technology. The scope includes re-using the existing chimneys, new booster ID fans, ductwork, spray dry absorbers, fabric filter (baghouse) addition, new rail spurs, lime unloading system, lime storage and handling system, lime slaking system, SDA solids recycle system, field erected tanks, disposal solids handling system, disposal solids silo, gypsum landfill, additional DCS, start-up transformers, unit auxiliary transformers, foundations, sitework, utility piping, and bulk electrical. An engineered building is included for the SDA solids recycle system and electrical equipment. The lime slaking system is located under the lime storage silos.

General Basis

- The mercury removal project will install fabric filters for removal of the particulate associated with the injection of activated carbon. As discussed in Section 7.2, these components would have to be upgraded with additional

WorleyParsons
resources & energy

Estimate Basis
Southern Company – Plant Scherer (4x900 MW)
Wet vs. Dry FGD Study

compartments for use in a dry FGD system. The cost for the additional bank of fabric filters is included in this study.

- Water treatment facilities are excluded.
- Gypsum dewatering facilities are excluded.
- Construction is based on multiple contracts with only one tier of overhead and profit.
- Crew rates are based on merit shop wage rates for Georgia. The crew rates include fringes, taxes, contractor indirect costs, and fee.
- The construction is based on 50-hour work-weeks.
- Removal of hazardous materials or site remediation is excluded.
- Aboveground and underground demolition and relocation allowances are included.
- All costs in the estimate are expressed in 4th Quarter 2006 dollars.
- Escalation is excluded.
- All taxes are excluded.
- BOP Engineering is included as an allowance.
- Construction management and start-up are by the Owner.
- General contingency of 15% is included.
- Owners' costs are excluded.
- Contractor's overhead and profit are included.
- Additional contractor's fees to cover risks typically associated on an EPC contract are excluded.

Budgetary Quotes Received

Wet FGD

- FGD Island (furnish & erect)
- Booster ID fans and motors
- CEMS
- DCS addition
- Limestone preparation system

Dry FGD

- SDA (furnish only)
- Booster ID fans and motors
- CEMS
- DCS addition
- Lime slaking system
- Lime storage silos
- Lime unloading & conveying system

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resources & energy

Estimate Basis
Southern Company – Plant Scherer (4x900 MW)
Wet vs. Dry FGD Study

- Disposal solids silo and handling system
- Stack & duct lining

APPENDIX K

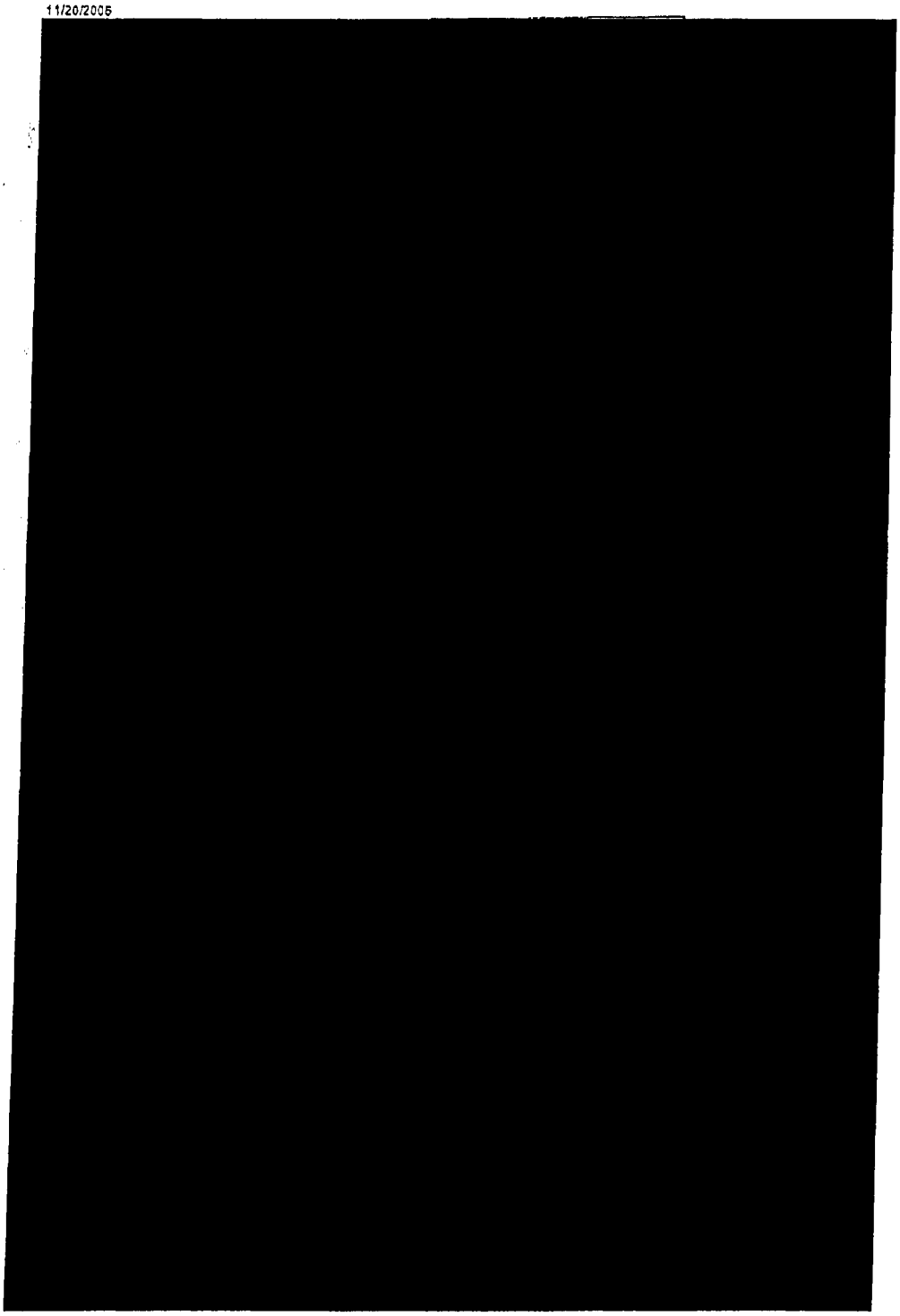
PROJECT CAPITAL COST ESTIMATES
WET & DRY

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CONCEPTUAL ESTIMATE

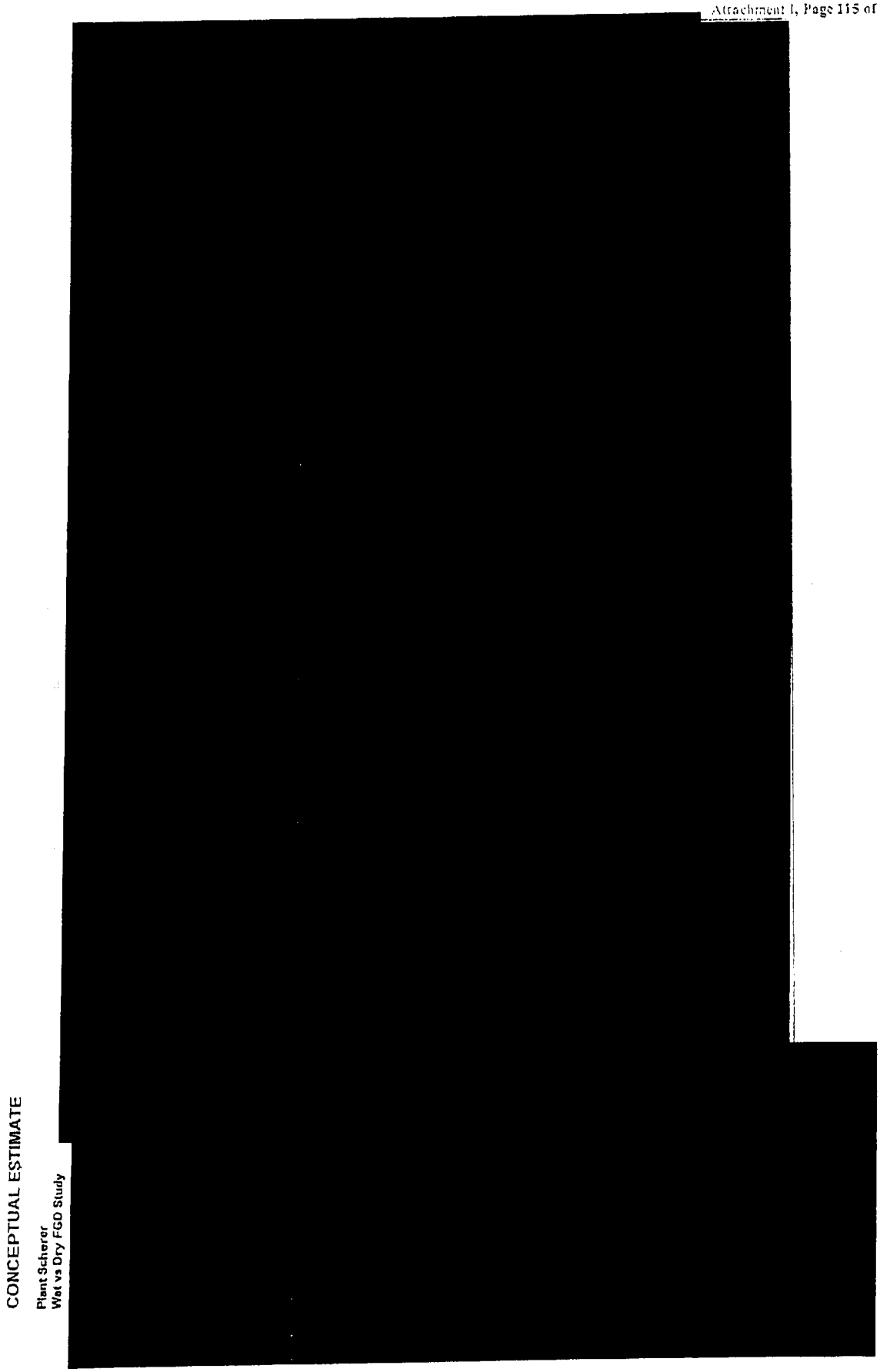
Plant Scherer
Wet vs Dry FGD Study

11/20/2006



Estimate summary - Plant Scherer Wet or Dry FGD Study 111706.xls

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CONCEPTUAL ESTIMATE

Plant Scherer
Wet vs Dry FGD Study

[redacted]

CONCEPTUAL ESTIMATE

Plant Scherer
Wet FGD Study

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[redacted]

CONCEPTUAL ESTIMATE

Plant Scherer
Dry FGD Study

APPENDIX L

MAJOR EQUIPMENT LISTS
WET & DRY

070007-Hearing Exhibit 000150

Plant Scherer
Wet FGD Major Equipment List

System	Equipment Name	Total Qty	Sizing Criteria	Size	Motor HP
1. Limestone Handling	Rail Spur	3	Minimum of one unit train reagent delivery		N/A
	Railcar Receiving Hopper - dual dischg	1	125 T capacity		N/A
	Vibratory Feeders (Receiving Hopper)	2	2200 TPH capacity		15
	Belt Feeder (Receiving Hopper)	1	2200 TPH capacity	72" belt, 110 fpm	
	Stockout Conveyor	1	2200 TPH capacity	48" belt, 500 fpm	15
	Belt Scale	1	48" belt		
	Magnetic Separator	1	48" belt		
	Dust Suppression System	1			15
	Limestone Radial Stacker	1	2200 TPH capacity	48" belt, 500 fpm	
	Reclaim Hoppers	2			
	Vibratory Feeders (Reclaim Hoppers)	2	480 TPH ea.		5
	Belt Feeders (Reclaim Hoppers)	2	480 TPH ea.	36" belt, 135 fpm	
	Reclaim Conveyors	2	480 TPH ea.	30" belt, 290 fpm	
	Limestone Day Bins w/Vent Filters	2	8 hr capacity	675 T	NA
2. Limestone Prep	Vibratory Feeders (Day Bins)	2	80 tph		3
	Slide Gates	2			N/A
	Weighbelt Feeder & Chutes	2	80 tph ea.		5
	Limestone Ball Mills	2	80 tph ea	15' dia x 30' lg	4000
	Mill Lubrication System	2			
	Mill Product Tank Agitator	2			15
	Mill Product Tank	2			N/A
	Classifier Feed Pumps	4			25
	Mill Classifier	2			N/A
	Limestone Slurry Storage Tank	1	8 hr working storage capacity	450,000 gal.	N/A
	Slurry Storage Tank Agitator	1			40
	Limestone Slurry Transfer Pumps	4			80
	Recycle Water Tank	1	8 hr working storage capacity	550,000 gal.	N/A
	Mill Area Sump Pumps	2			25
	Mill Area Sump Agitator	1			15
3. Wet FGD Area	Absorber Vessel	4	Single Pass		N/A
(Advatech Scrubber Island)	Absorber Recirc Pumps	36			1200
	Oxidation Air Blowers	8			2500
	Absorber Bleed Pumps	8			30
	Absorber Agitators	24			75
	Sump Pumps	4			25
	Sump Agitators	4			15

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Plant Scherer
Wet FGD Major Equipment List

System	Equipment Name	Total Qty	Sizing Criteria	Size	Motor HP
	Limestone Slurry Feed Tanks	2	2 hr storage capacity		N/A
	Limestone Slurry Feed Tank Agitators	2			40
	Limestone Slurry Feeds Pumps	8			80
4. Flue Gas System	Booster Fans	8			12000
	Stack Bypass Dampers w/Actuator	4			
	Bypass Damper Seal Air Fans	8			60
	WFGD Inlet Damper w/Actuator	4			
	WFGD Inlet Damper Seal Air Fans	8			50
5. Mech. BOP Equipment	Service Air Compressors	4			
	Air Receivers	3			
	Instrument Air Dryers	3			
	Reclaim Water Pumps	2			
	Recycle water Feed Pumps	2			
6. Electrical Distribution Sys.	FGD Service Transformers	4	25KV-13.8KV-13.8KV	50/66/83 MVA	
	FGD MV Transformers	8	13.8-4.16 KV	13/17/21 MVA	
	FGD Startup Transformers	2	115KV-13.8KV-13.8KV	50/66/83 MVA	
	13.8 KV Switchgear	1 Lt			
	4.16 KV Switchgear	1 Lt			
	Unit Substations	1 Lt			
	480V Motor Control Centers	1 Lt			
7. Control System	I/O Cabinets	1 Lt			
	Processor Cabinets	1 Lt			
	Engr Workstations	2			

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Plant Scherer
Dry FGD Major Equipment List

System	Equipment Name	Total Qty	Sizing Criteria	Size	Motor HP
1. Lime Handling	Rail Spur	3	Minimum of one unit train reagent delivery		N/A
	Railcar Receiving Hopper - below grade	2	2200 TPH capacity		N/A
	Belt Feeder	1	2200 TPH capacity	72" BW, 24-120 FPM, 37' long	60
	Stockout Conveyor	1	2200 TPH capacity	60" BW, 500 FPM, 960' long	700
	Silo Conveyor on top of silos	1	2200 TPH capacity	60" BW, 500 FPM, 360' long	100
	Traveling Tripper on top of Silos	1	2200 TPH capacity		10
	Lime Bulk Storage Silos	6	30 Day Storage Combined (60,000 tons)	60'Dia x 200'H, Concrete	N/A
2. Lime Prep	Live Bottom Feeders	6	0 to 50 TPH		5
	Rotary Feeders	6	1 to 50 TPH		
	Weigh Belt Feeders	6	0 to 50 TPH	30" belt	15
	Hot Water Heaters	6	Match slaker water need		
	Vertimil Lime Slakers	6	2,000 TPD Lime feed Total, 3 op, 3 spare		
	Separating Chambers	6			
	Slurry Recycle Pumps	6			
	Slurry Product Pumps	6			20
	Lime Slurry Storage Tank	1	8 hour capacity - 4 units		
	Lime Slurry Tank Agitator	1			40
	Lime Slurry Transfer Pumps	2			80
	Sump Pumps	2	Area Washdown		15
	Sump Agitator	1			25
3. Dry FGD Area	Lime Slurry Feed Tanks	2	2 hr capacity - 2 units		
	Feed Tank Agitators	2			
	Lime Slurry Feed Pumps	4			
	Spray Dryer Absorbers	12			
	Rotary Atomizers	36			
	SDA Hopper Heaters	12			
	Rotary Airlock Valves	12			
	Atomizer Feed Tanks	4			40
	Atomizer Feed Tank Agitators	4			80
	Atomizer Feed Pumps	8			25
	SDA Area Sump Pumps	4			
	SDA Area Sump Pump Agitators	2			
4. Fabric Filter System (Addition)	Pulse Jet Fabric Filter - Add'l Cmprts	24			
	Pulse Air Compressors	--	(Existing)		
	Hopper Heaters	24			

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Plant Scherer
Dry FGD Major Equipment List

System	Equipment Name	Total Qty	Sizing Criteria	Size	Motor HP
	Compartment Inlet Louver Dampers	24			
	Compartment Outlet Poppet Dampers	24			
	Bags and Cages	20,160			
5. Recycle Solids System	Recycle Solids Silos	4	8 hr capacity		
	Live Bottom Feeders	4			
	Rotary Feeders	4			
	Weigh Belt Feeders	4			
	Recycle Mix Tanks	4			
	Recycle Mix Tank Agitators	4			
	Recycle Slurry Storage Tanks	4			
	Recycle Slurry Storage Tank Agitators	4			
	Recycle Slurry Feed Pumps	8			
6. Flue Gas System	Booster Fans	8			6500
	Stack Bypass Damper w/Actuator	4			
	Stack Bypass Damper Seal Air Fans	8			50
	SDA Inlet Damper w/Actuator	4			
	SDA Inlet Damper Seal Air Fans	8			50
	SDA Outlet Damper w/Actuator	4			
	SDA Outlet Damper Seal Air Fans	8			50
7. By-Product Solids Handling	Conveying Air Blowers	4			
	Pressure Feeders	120			
	Pressure Feeder Bodies	120			
	Pressure Feeder Valving	1 Lt			
	By-Product Silos	2	5,000T ea.		
	Silo Fluidizing System	2			
	Mixer/Unloaders	2			
8. Mech. BOP Equipment	Service Air Compressors	4			
	Air Receivers	3			
	Instrument Air Dryers	3			
9. Electrical Distribution Sys.	FGD Service Transformers	4	25KV-6.9KV-6.9KV	30/40/50 MVA	
	FGD Startup Transformers	2	115KV-6.9KV-6.9KV	30/40/50 MVA	
	6.9 KV Switchgear	1 Lt			
	Unit Substations	1 Lt			

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Plant Scherer
Dry FGD Major Equipment List

System	Equipment Name	Total Qty	Sizing Criteria	Size	Motor HP
	480V Motor Control Centers	1 Lt			
10. Control System	I/O Cabinets	1 Lt			
	Processor Cabinets	1 Lt			
	Engr Workstations	2			

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APPENDIX M

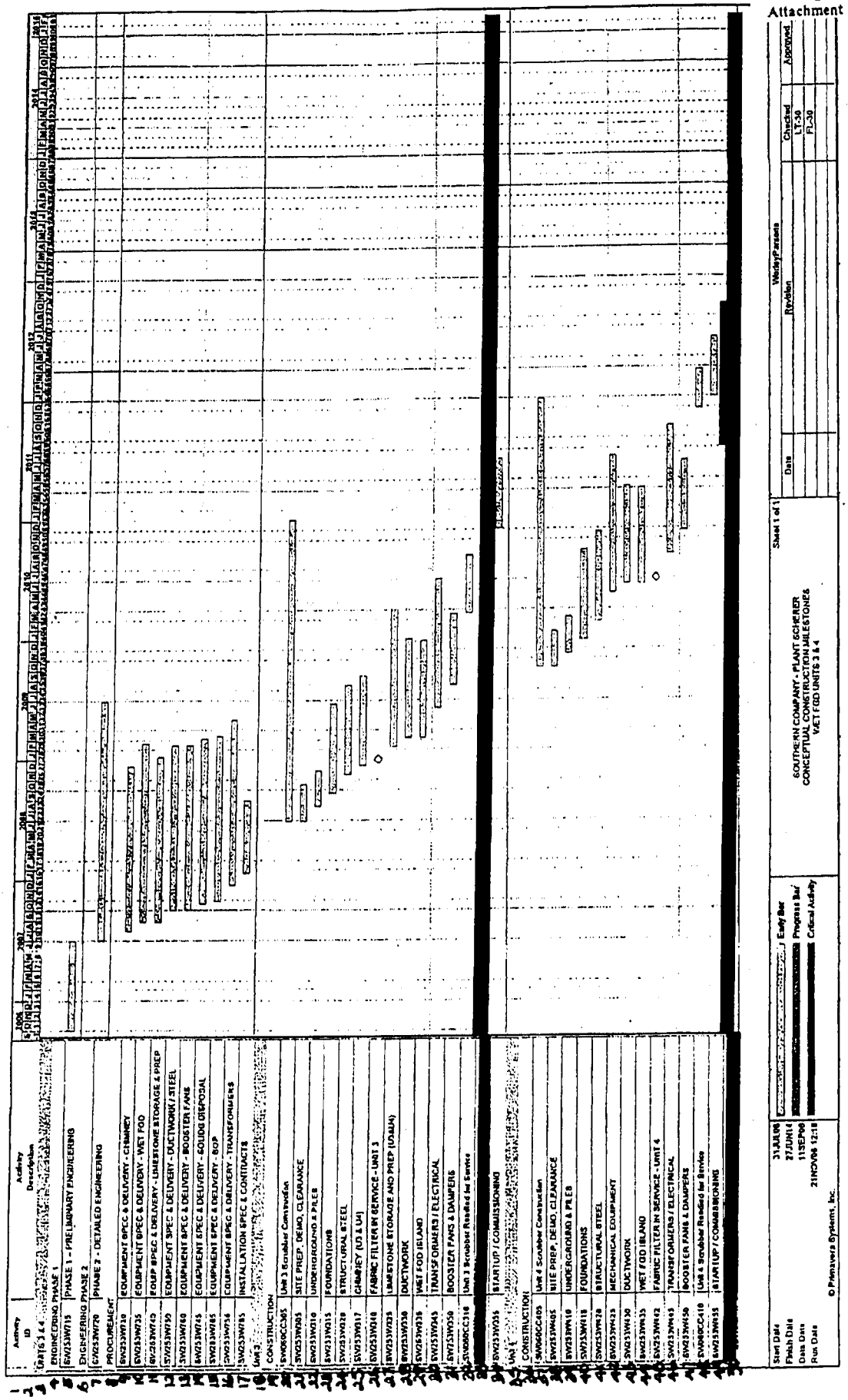
PROJECT MILESTONE SCHEDULES
WET & DRY

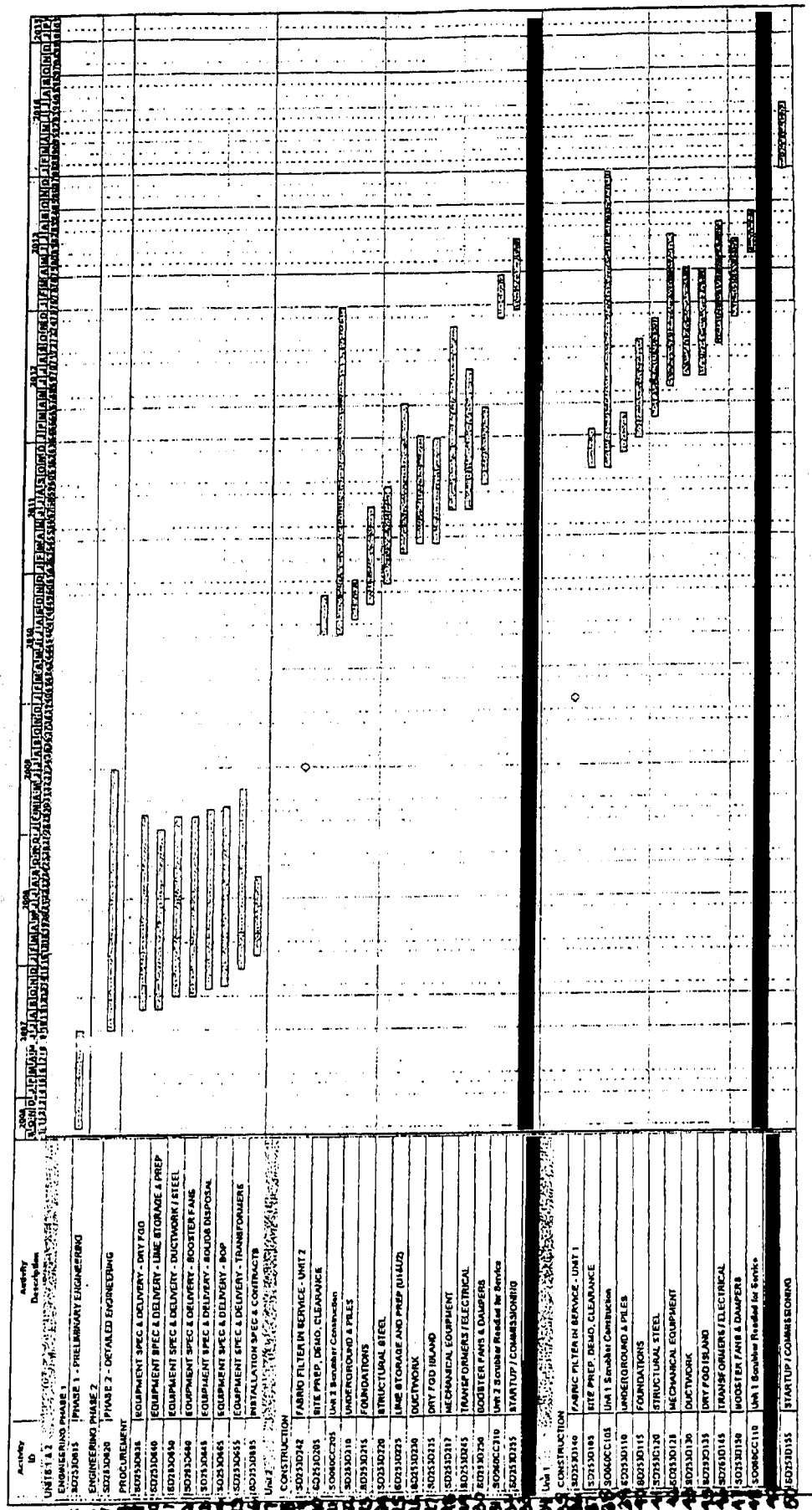
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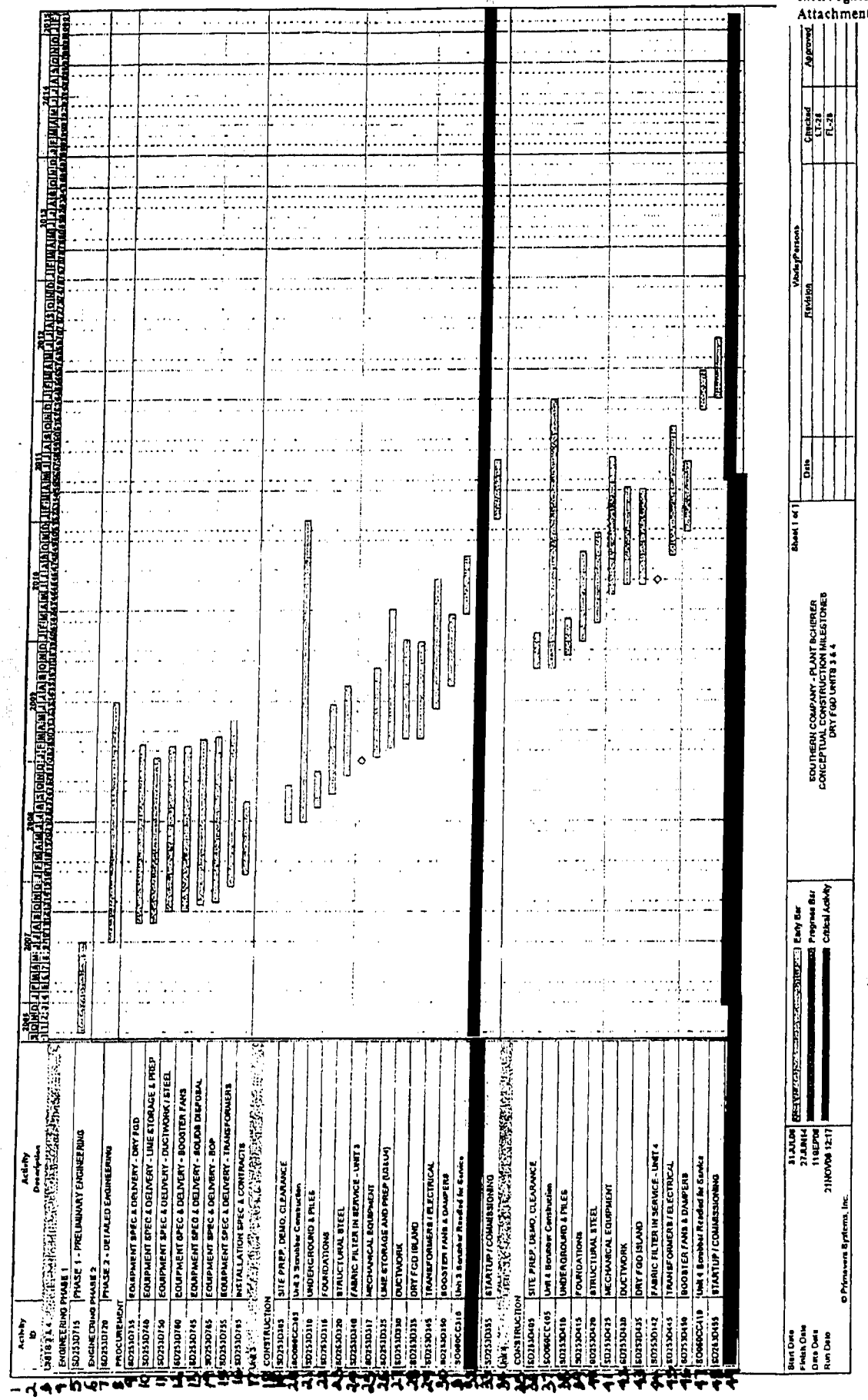
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SOUTHERN COMPANY - PLANT SCHERER
CONCEPTUAL CONSTRUCTION MILESTONES
DRY FGD UNITS 1 & 2
Sheet 1 of 1
WhitleyPenn
Date
Revision
Checked
LT-28
FL-28
Approved
Start Date 31JUL06
Finish Date 27JUN14
Data Date 11SEP06
Run Date 21NOV06 12:18
Early Bar
Progress Bar
Critical Activity
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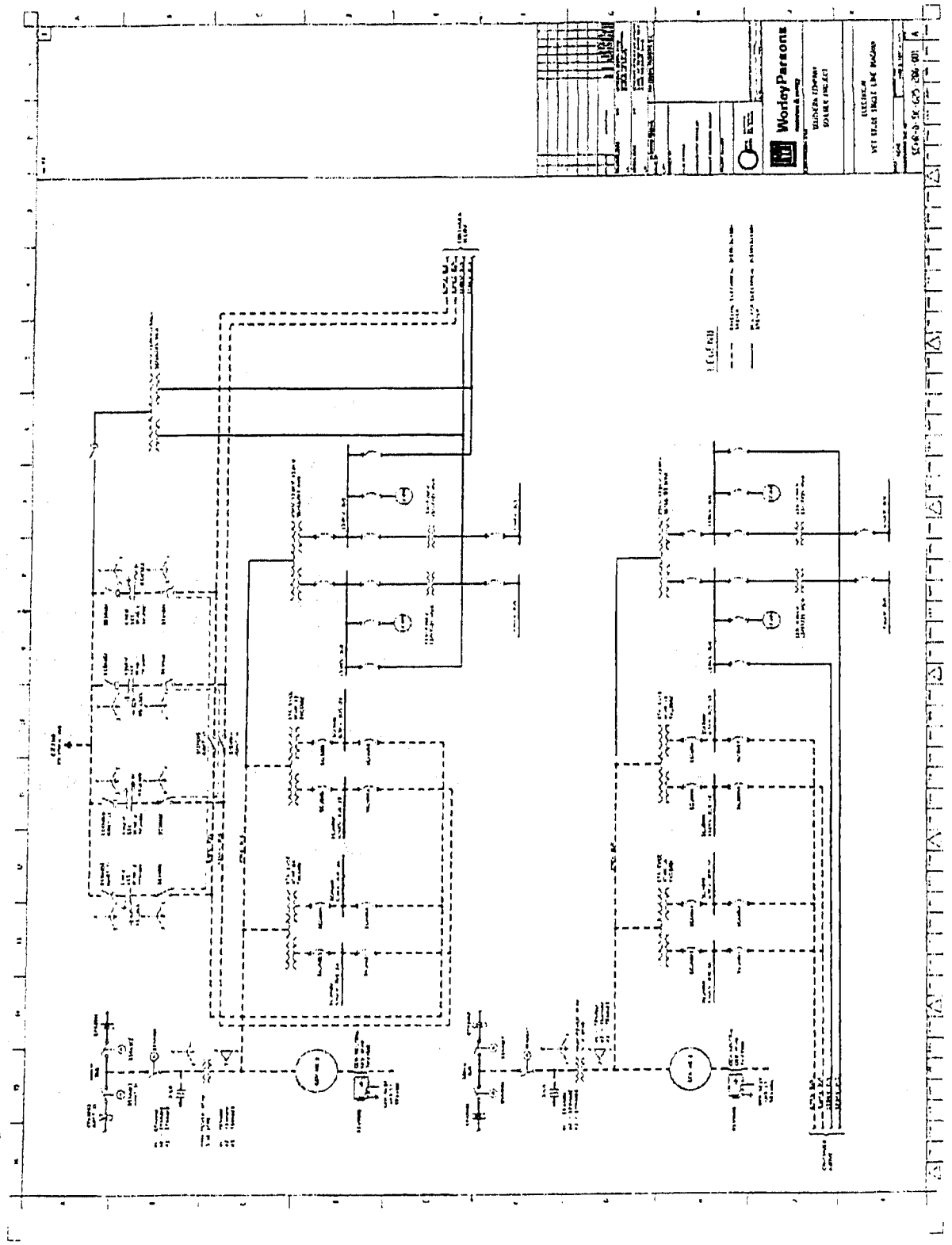

SOUTHERN COMPANY - PLANT SCHERER
CONCEPTUAL CONSTRUCTION MILESTONES
DRY FGD UNITS 3 & 4
Sheet 1 of 1
Start Date 31JUL06
Finish Date 27JAN14
Data Date 11SEP06
Run Date 21NOV06 12:17
Early Bar
Progress Bar
Critical Activity
Date
Revision
Vbels/Parsons
Checked
Approved
LT-28
FL-28
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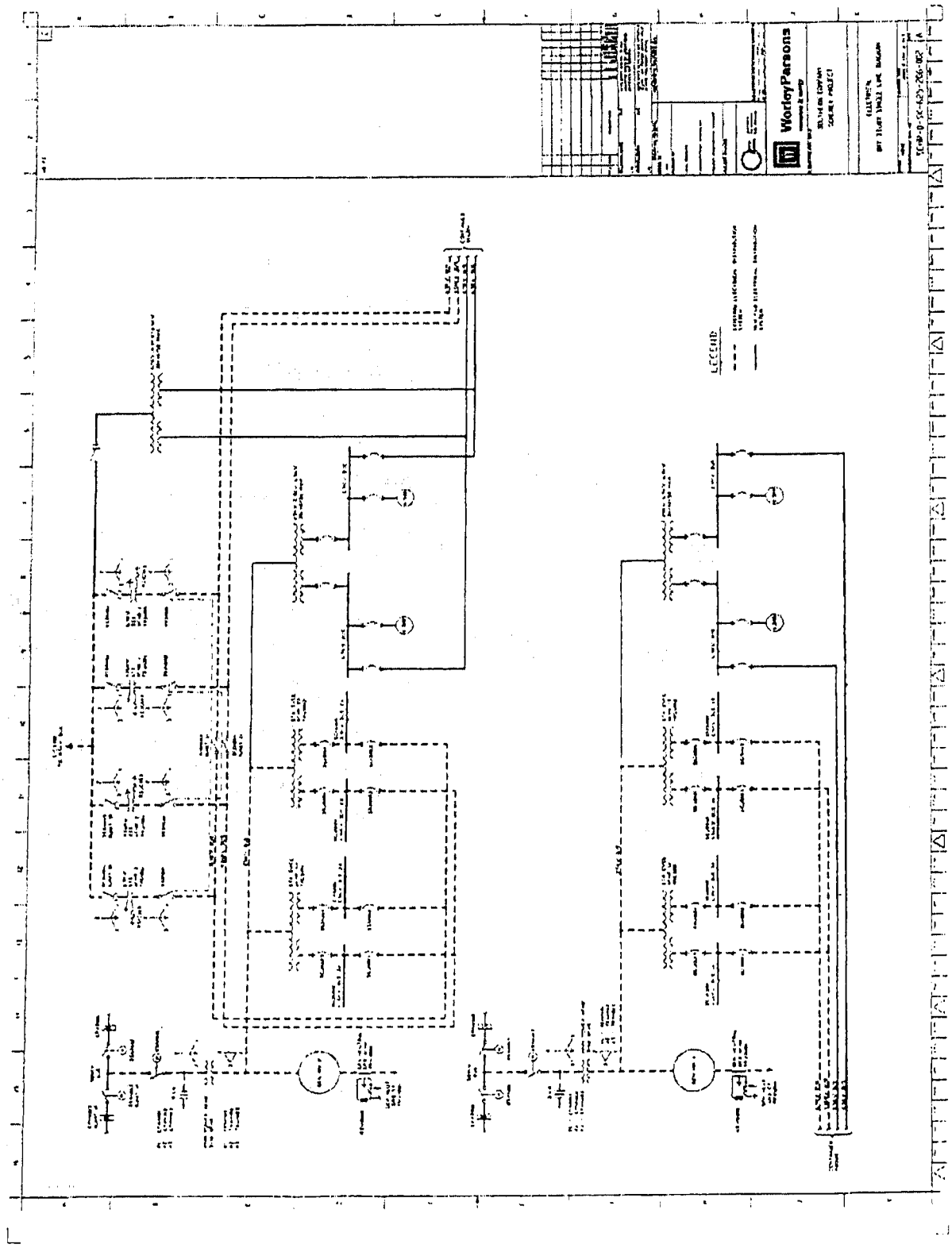
APPENDIX N

ELECTRICAL SINGLE-LINE DIAGRAMS
(Typical – Units 1 & 2)
WET & DRY

SCHR-0-SK-625-206-001
SCHR-0-SK-625-206-002

WorleyParsons


WorleyParsons


WorleyParsons

Annual System Emissions Reduction by Polutant

Site	SJRPP Unit 1 & 2	SJRPP Unit 1 & 2	Scherer 4	Scherer 4	Martin 1 & 2 - Manatee 1 & 2		
Project:	SCR with Ammonia Injection	SCR with Ammonia Injection	Wet FGD Scrubber	Baghouse & Mercury Sorbant Injection	800 MW Cycling Project	800 MW Cycling Project	800 MW Cycling Project
Year	Yearly NOx Reduction (Tons)	Yearly NOx Reduction (Tons)	Yearly SO2 Reduction (Tons)	Yearly Mercury Reduction (Tons)	Yearly SO2 Reduction (Tons)	Yearly NOx Reduction (Tons)	Yearly CO2 Reduction (Tons)
2008	3,611	0	0	0.00	0	0	0
2009	7,666	0	0	0.00	6,619	2,627	1,137,423
2010	7,644	0	0	0.10	9,401	3,293	1,336,497
2011	7,669	0	0	0.14	7,376	4,355	1,485,389
2012	7,723	2,340	15,618	0.13	7,969	4,873	1,612,764
2013	7,706	2,951	19,534	0.13	8,507	4,762	1,622,297
2014	7,690	2,929	19,535	0.13	8,690	4,195	1,496,406
2015	7,138	2,929	19,537	0.13	8,039	4,559	1,567,416
2016	3,294	2,931	19,591	0.13	6,393	4,113	1,373,473
2017	3,270	2,939	19,535	0.13	6,261	4,532	1,469,354
2018	3,274	2,924	19,488	0.13	8,058	4,904	1,582,008
2019	3,277	2,924	19,513	0.13	9,196	4,882	1,593,025
2020	3,287	2,945	19,591	0.13	8,216	5,240	1,642,888
2021	3,284	2,940	19,534	0.13	7,921	5,136	1,622,994
2022	3,278	2,935	19,534	0.13	8,005	4,892	1,679,445
2023	3,273	2,925	19,536	0.13	6,658	4,691	1,690,528
2024	3,319	2,976	19,594	0.13	6,769	4,271	1,712,155
2025	3,283	2,945	19,497	0.13	6,716	4,533	1,774,348

Q.
What entities were solicited and what entities responded to RFPs with bids for each CAIR/CAMR project valued at over $1 Million?

A.
For the reburn and low NOx burner projects, four entities (G.E., B&W, Ansaldo, and Mobotec) were requested to provide proposals for the 400 MW units and two entities (G.E. and Mobotec) provided proposals. For the Putnam water injection project, the combustion turbine OEM Siemens provided a Customer Informational Letter outlining the modifications necessary and estimated costs. Siemens was considered the only viable source for supplying the parts and services for the Putnam Units due to the complexity of implementing a modification such as water injection on a gas turbine.

FPL did not issue any RFPs for CAIR/CAMR projects Related to St. Johns River Power Park (SJRPP) or Scherer Unit 4. FPL is a non-operating partial owner of SJRPP and Scherer Unit 4. Services are procured for SJRPP by JEA on their own behalf and as agent for FPL. Equipment and services are procured for Plant Scherer by Georgia Power Company/Southern Company on their behalf and as agent for the six other co-owners.

Q.

Provide a financial analysis comparing the retrofit of FPL's Scherer 4 as proposed by FPL with replacement generation based on a natural gas combined cycle unit, considering base, high, and low fuel price sensitivities. Consider the most cost effective approach available to FPL regarding the physical location of the combined cycle unit.

A.

FPL has ownership and contractual commitments to pay its share of the capital and operating costs of Scherer 4, which FPL must pay regardless of how much energy output FPL takes from Scherer 4. Thus, FPL would not avoid having to pay its share of Scherer 4 costs, other than its portion of variable costs, if it decided to build an additional combined cycle unit and took power from that unit instead of Scherer 4. While FPL has not performed a formal economic analysis of that alternative, considering that the energy costs for combined cycle generation are significantly greater than the energy costs of Scherer 4, FPL strongly doubts that one could economically justify the costs of building and operating a combined cycle unit with just the avoided Scherer 4 variable costs.

Q.

Provide a financial analysis comparing the retrofit of FPL's Scherer 4 as proposed by FPL with replacement generation based on a natural gas combined cycle unit (s), considering base, high, and low future carbon capture/sequestration requirements sensitivities. Consider the most cost effective approach available to FPL regarding the physical location of the combined cycle unit.

A.

FPL believes that it is inappropriate to evaluate the replacement of FPL's ownership share of Scherer Unit 4 with gas fired combined cycle technology as described in the response to interrogatory question 38.

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Q.
What are the FGD technologies proposed for the Scherer Units 1 through 4, the proposed installation dates, and the relative costs of the units? What synergies and cost savings, if any, are planned in the design, procurement, and installation of Scherer Units 1 through 4 by a single vendor or group of vendors working together?

A.
The proposed FGD technology for Scherer Units 1 through 4 is the Advatech Wet FGD (Wet Scrubber).

Current required operation dates of the flue gas desulfurization and total cost estimates (as of 08/10/2007) are as follows:

Unit 1	Operational Prior to 12/31/2014
Unit 2	Operational Prior to 12/31/2013
Unit 3	Operational Prior to 12/31/2011
Unit 4	Operational Prior to 12/31/2012

[redacted]

FPL's share of the cost of the Unit 4 FGD upgrade is [redacted]

Georgia Power Company acting as Operating Agent per contractual agreement has selected the Advatech Wet Scrubber with the goal of completing the detail design for all four Scherer units within 18 months and commit to equipment procurement for all units for better pricing and lower risk.

Southern Company, parent to Georgia Power Company, has a bulk procurement program to leverage price and other contractual concessions based on the volume of materials purchased for the fleet of environmental projects being executed within their system.

Georgia Power Company is developing a construction bid package strategy that will utilize contractor cost in the most efficient manner. An example is to bid piling / caisson installation packages for SCR and FGD for all four Scherer units.

In every phase of the project Georgia Power Company has committed to look for ways to improve efficiencies.

Q.

Show how the aggregate emissions of FPL, both with and without the planned controls, compare to FPL's expected annual emission allowances.

A.

Attachment I shows the system total emissions, before and after the planned controls.

Total System Emissions with and without planned controls

	Base Assumptions			With Controls			Incremental System Emissions		
	(1)	(2)	(3)	(4)	(5)	(6)	(7) =(4) - (1)	(8) =(5) - (2)	(9) =(6) - (3)
Year	SO2 System Emissions Tons	NOx System Emissions Tons	Hg System Emissions Tons	SO2 System Emissions Tons	NOx System Emissions Tons	Hg System Emissions Tons	SO2 System Emissions Tons	NOx System Emissions Tons	Hg System Emissions Tons
2008	109,019	47,611	0.41	109,065	44,000	0.41	45	-3,611	0.00
2009	110,897	46,045	0.43	104,369	35,749	0.43	-6,528	-10,295	0.00
2010	89,247	40,047	0.35	79,945	29,118	0.25	-9,302	-10,929	-0.10
2011	64,931	34,976	0.32	57,637	22,973	0.18	-7,294	-12,003	-0.14
2012	65,388	35,642	0.32	41,912	20,727	0.19	-23,476	-14,915	-0.13
2013	66,776	35,739	0.32	38,861	20,360	0.19	-27,915	-15,379	-0.13
2014	72,703	37,569	0.32	44,644	22,758	0.19	-28,059	-14,811	-0.13
2015	64,962	36,067	0.31	37,489	21,443	0.18	-27,473	-14,624	-0.13
2016	56,845	31,673	0.25	30,954	21,330	0.12	-25,891	-10,343	-0.13
2017	53,167	30,071	0.25	27,451	19,339	0.12	-25,716	-10,732	-0.13
2018	55,910	28,304	0.25	28,394	17,193	0.12	-27,516	-11,111	-0.13
2019	60,179	28,904	0.25	31,551	17,817	0.12	-28,628	-11,086	-0.13
2020	55,497	28,004	0.25	27,756	16,538	0.12	-27,741	-11,466	-0.13
2021	55,039	28,406	0.25	27,665	17,065	0.12	-27,374	-11,341	-0.13
2022	55,899	28,569	0.25	28,453	17,481	0.12	-27,446	-11,087	-0.13
2023	51,859	27,912	0.25	25,759	17,019	0.12	-26,100	-10,893	-0.13
2024	52,013	27,817	0.25	25,723	17,326	0.12	-26,290	-10,491	-0.13
2025	46,624	26,758	0.22	20,567	16,015	0.09	-26,058	-10,743	-0.13

Note: *The values above are based on FPL's sytem capability; ie.,FPL units and purchases.*

Controls:

SJRPP Unit 1 and 2: -SCR with ammonia injection
-Mercury CEMS

Scherer 4: -Wet FGD Scrubber
-SCR with ammonia injection
-Fabric filter baghouse & mercury sorbant injection
-Mercury CEMS

Manatee Unit 1 and 2; Martin Unit 1 and 2:
-800 MW cycling project

Q.
Provide FPL's comparison of the ECRC cost of implementing the originally-planned reburn and low NOx burner projects at Cape Canaveral, Port Everglades, Turkey Point, and Putnam plants, plus required NOx allowance costs, to the cost of installation of the proposed 800 MW cycling project, plus required NOx allowance costs.

A.
FPL has not compared the costs of implementing the reburn and low NOx burner projects to the costs of 800 MW cycling projects. The 800 MW project, in addition to substantial emission savings, produces large fuel savings which makes it more cost-effective than any other project under consideration for FPL's CAIR compliance strategy. In FPL's strategy, the gas reburn and low NOx burner projects were considered to be additional or complimentary projects to the 800 MW cycling project.

Q.
Who provided the detailed information contained in Exhibit RRL-5 of Witness LaBauve's direct testimony of August 3, 2007?

A.
APTECH, an engineering firm, was contracted by FPL to provide the detailed information.

Q.

What method(s) is FPL using to solicit vendors for the design, procurement, and construction of the 800 MW Unit Cycling Project in the most cost effective way?

A.

FPL is utilizing the normal, established company procurement process. This provides controls, access to favorable FPL rates with vendors and takes advantage of economy of scale where applicable. Work on the first unit will begin in 2008. Bids have been received for the finishing superheater tube (FSH) replacements and a review is in progress. Specifications for the heat recovery area (HRA) drains have been developed and are being reviewed by FPL engineering personnel.

Q.

How might future carbon capture requirements impact the full implementation of the 800 MW Unit Cycling Project, as referenced on Page 11 of Witness LaBauve's August 3, 2007 direct testimony?

A.

The 800 MW Unit Cycling Project is anticipated to produce both reductions in NOx emissions and associated reductions in fuel use. Reductions in fuel use will produce related reductions in emission of CO2. Prior to the availability of commercially available cost-effective carbon capture equipment for fossil steam generating units, FPL is unaware of any effects, either positive or negative, of the individual projects being performed as part of the 800 MW Unit Cycling Project on the ability to add future carbon capture equipment.

Q.
What impact is the proposed 800 MW unit cycling project expected to have on fuel costs for each generating unit?

A.
It is important to note that in deciding whether the cycling project is economic, the relevant fuel costs are the system costs, not the fuel costs of the individual 800 MW units. Attachment I, shows the system fuel costs, before and after the cycling projects.

System Production Cost Difference Due to Economically Cycling of the 800 MW Units

	(1)	(2)	(3) =(2)-(1)
YEAR	Base Case with economically cycling 800 MW units Cost ($M)	Change Case without economically cycling 800 MW units Cost ($M)	System FUEL SAVINGS ($M)
2007	5,246	5,246	0
2008	5,569	5,569	0
2009	5,105	5,202	97
2010	5,168	5,230	62
2011	4,986	5,054	68
2012	5,330	5,433	103
2013	5,614	5,704	90
2014	5,825	5,933	108
2015	6,357	6,454	98
2016	7,078	7,192	114
2017	7,715	7,838	123
2018	8,126	8,276	151
2019	8,707	8,845	139
2020	9,105	9,280	175
2021	9,448	9,634	186
2022	9,974	10,181	207
2023	10,497	10,748	251
2024	11,191	11,443	252
2025	11,989	12,265	276

Q.
Provide the updated annual price projections for SO2, NOx, and mercury allowances. Compare to the cost of CAIR/CAMR compliance for each unit by year under FPL's most recent CAIR/CAMR plan.

A.
The annual price projections for SO2, NOx, and mercury are shown in Attachment I.

FPL has compared the costs of its CAIR/CAMR strategy versus a strategy where FPL relies only in the purchase of allowances. This is done at the system level, not at the unit level, as FPL believes that the proper comparison is at the system level. This system-level comparison is provided in Attachment II.

Nominal $/Ton

Year	NOx $/Ton	SO2 $/Ton	Hg $/Ton
2008	0	972	0
2009	1,674	1,065	0
2010	1,826	1,165	59,971,424
2011	1,991	1,276	59,360,067
2012	2,182	1,398	58,754,359
2013	2,391	1,532	58,154,370
2014	2,619	1,677	60,539,881
2015	2,867	1,838	66,290,458
2016	3,140	2,013	72,584,634
2017	3,436	2,203	79,445,273
2018	3,761	2,411	86,708,345
2019	4,116	2,638	95,175,091
2020	4,506	2,888	104,170,294
2021	3,337	3,163	114,099,102
2022	2,473	3,465	124,973,551
2023	1,831	3,795	136,885,007
2024	1,356	4,155	149,931,006
2025	1,004	4,552	164,218,862

Revenue Requirements: Base Case

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Year	Annual Discount Factor at 0.08302	Incremental Generation Capital (Millions)	System Generation Variable O&M (Millions)	Incremental Generation Fixed O&M (Millions)	Total System Fuel (Millions)	Total Emission Costs* (Millions)	Annual Costs (Millions)	NPV Annual Cost (Millions)	NPV Cumulative Costs (Millions)
2008	1.000	0	97	0	5,745	106	5,948	5,948	5,948
2009	0.923	0	100	0	6,148	17	6,266	5,785	11,733
2010	0.853	0	109	0	6,174	9	6,292	5,364	17,098
2011	0.787	0	113	0	6,006	83	6,202	4,882	21,980
2012	0.727	0	119	0	5,724	226	6,069	4,411	26,391
2013	0.671	0	121	0	5,991	403	6,515	4,373	30,763
2014	0.620	0	122	0	6,484	508	7,114	4,409	35,172
2015	0.572	0	131	0	7,066	653	7,850	4,491	39,664
2016	0.528	0	136	0	7,698	725	8,559	4,522	44,186
2017	0.488	0	149	0	8,029	891	9,069	4,424	48,609
2018	0.450	0	154	0	8,188	1,051	9,393	4,231	52,840
2019	0.416	0	158	0	8,684	1,221	10,062	4,185	57,025
2020	0.384	0	160	0	8,950	1,403	10,513	4,037	61,062
2021	0.355	0	170	0	9,392	1,553	11,115	3,941	65,004
2022	0.327	0	177	0	10,008	1,821	12,006	3,931	68,934
2023	0.302	0	187	0	10,594	1,999	12,780	3,863	72,798
2024	0.279	0	197	0	11,384	2,283	13,863	3,870	76,667
2025	0.258	0	210	0	12,192	2,419	14,822	3,820	80,487
	Total NPV =	0	1,315	0	72,506	6,667	80,487		

Revenue Requirements: Planned Controls Implemented

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Year	Annual Discount Factor at 0.08302	Incremental Generation Capital (Millions)	System Generation Variable O&M (Millions)	Incremental Generation Fixed O&M (Millions)	Total System Fuel (Millions)	Total Emission Costs* (Millions)	Annual Costs (Millions)	NPV Annual Cost (Millions)	NPV Cumulative Costs (Millions)
2008	1.000	10	98	1	5,747	106	5,962	5,962	5,962
2009	0.923	24	105	2	6,029	10	6,169	5,696	11,658
2010	0.853	57	119	2	6,049	(2)	6,225	5,307	16,965
2011	0.787	58	123	2	5,838	74	6,095	4,798	21,763
2012	0.727	111	133	2	5,542	193	5,981	4,347	26,110
2013	0.671	126	136	2	5,803	360	6,427	4,314	30,424
2014	0.620	121	138	2	6,308	461	7,030	4,357	34,781
2015	0.572	121	146	2	6,872	602	7,743	4,430	39,211
2016	0.528	115	148	2	7,519	673	8,457	4,468	43,679
2017	0.488	113	159	2	7,828	835	8,937	4,360	48,038
2018	0.450	108	165	2	7,974	985	9,234	4,159	52,197
2019	0.416	105	168	2	8,474	1,145	9,895	4,115	56,312
2020	0.384	100	171	2	8,712	1,323	10,308	3,958	60,271
2021	0.355	97	181	2	9,144	1,467	10,891	3,862	64,132
2022	0.327	93	188	2	9,743	1,726	11,752	3,847	67,980
2023	0.302	90	196	2	10,307	1,900	12,495	3,777	71,757
2024	0.279	85	207	2	11,085	2,174	13,553	3,783	75,540
2025	0.258	83	221	2	11,869	2,301	14,475	3,731	79,271
Total NPV =		820	1,415	19	70,784	6,234	79,271		

Controls:

SJRPP Unit 1 and 2:
- -SCR with ammonia injection
- -Mercury CEMS

Scherer 4:
- -Wet FGD Scrubber
- -SCR with ammonia injection
- -Fabric filter baghouse & mercury sorbant injection
- -Mercury CEMS

Manatee Unit 1 and 2; Martin Unit 1 and 2:
- -800 MW cycling project

Change in Revenue Requirements: (Planned Controls Implemented) - (Base Case)

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Year	Annual Discount Factor at 0.08302	Incremental Generation Capital (Millions)	System Generation Variable O&M (Millions)	Incremental Generation Fixed O&M (Millions)	Total System Fuel (Millions)	Total Emission Costs* (Millions)	Annual Costs (Millions)	NPV Annual Cost (Millions)	NPV Cumulative Costs (Millions)
2008	1.000	10	1	1	2	0	14	14	14
2009	0.923	24	4	2	(119)	(7)	(96)	(89)	(75)
2010	0.853	57	10	2	(125)	(11)	(67)	(57)	(132)
2011	0.787	58	11	2	(168)	(9)	(107)	(84)	(217)
2012	0.727	111	14	2	(183)	(33)	(88)	(64)	(281)
2013	0.671	126	15	2	(188)	(43)	(88)	(59)	(340)
2014	0.620	121	16	2	(176)	(47)	(84)	(52)	(392)
2015	0.572	121	15	2	(195)	(51)	(107)	(61)	(453)
2016	0.528	115	12	2	(179)	(52)	(102)	(54)	(507)
2017	0.488	113	11	2	(201)	(57)	(132)	(64)	(571)
2018	0.450	108	11	2	(214)	(66)	(160)	(72)	(643)
2019	0.416	105	11	2	(210)	(76)	(167)	(69)	(713)
2020	0.384	100	11	2	(238)	(80)	(205)	(79)	(791)
2021	0.355	97	11	2	(248)	(87)	(224)	(80)	(871)
2022	0.327	93	10	2	(265)	(95)	(255)	(83)	(954)
2023	0.302	90	9	2	(287)	(99)	(285)	(86)	(1,040)
2024	0.279	85	10	2	(299)	(109)	(311)	(87)	(1,127)
2025	0.258	83	10	2	(324)	(119)	(347)	(89)	(1,217)
Total NPV =		820	100	19	(1,721)	(434)	(1,217)		

Notes: *Negative Indicates Savings*

Controls:

SJRPP Unit 1 and 2: -SCR with ammonia injection
-Mercury CEMS

Scherer 4: -Wet FGD Scrubber
-SCR with ammonia injection
-Fabric filter baghouse & mercury sorbant injection
-Mercury CEMS

Manatee Unit 1 and 2; Martin Unit 1 and 2:
-800 MW cycling project

Florida Power & Light's Responses to

Staff's 5th ROGS Nos. 48 - 65

070007

Q.
Describe in detail the facilities FPL currently uses to temporarily store low level radioactive waste until it is disposed of at the Barnwell Low-Level Radioactive Waste Disposal Facility?

A.
The facilities that FPL currently uses to temporarily store its solid low level radioactive waste consist of spent resin storage tanks, shipping/disposal containers and shielded casks. The facilities are used to accumulate the low level radioactive waste produced as a result of plant operations and maintenance prior to shipping it to licensed off-site facilities for processing and/or disposal.

St. Lucie
There are two spent resin storage tanks (one in each unit's Reactor Auxiliary Building) at the St. Lucie Nuclear Plant which are used to accumulate spent ion exchanger resins. Each spent resin storage tank has a capacity of approximately 400 cubic feet. When the spent resin storage tank is ready to be transferred, the spent ion exchanger resin is sluiced to a shipping/disposal container, which is subsequently shipped to a licensed off-site facility for processing and/or disposal. Alternatively, some of the spent ion exchanger resins are sluiced directly from the ion exchanger to a shipping/disposal container prior to being shipped off-site for processing and/or disposal.

To minimize radiation fields in the plant and to reduce low level radioactive waste disposal costs, the spent resin storage tanks are typically used to accumulate spent ion exchanger resins with lower levels of radioactivity. Since Class A low level radioactive waste will continue to be disposed of at a licensed low level waste disposal facility in Utah, keeping the spent ion exchanger resin with lower levels of radioactivity segregated from the spent ion exchanger resin with higher levels of radioactivity will minimize the volume of spent ion exchanger resin that will have to be stored on-site after June 30, 2008. The spent ion exchanger resins with higher levels of radioactivity, which are generally characterized as Class B or Class C low level radioactive waste, are currently sluiced directly to a shipping/disposal container prior to shipment to a licensed off-site facility for processing and/or disposal at the Barnwell Low-Level Radioactive Waste Disposal Facility.

The St. Lucie Plant also generates low-level radioactive waste filters that are used to remove suspended particles from the primary water systems. The filters that are required to be disposed of at the Barnwell Low-Level Radioactive Waste Disposal Facility are accumulated in a shipping/disposal container within a shielded cask. Other highly contaminated dry solid low level radioactive waste material is similarly collected in a shipping/disposal container within a shielded cask. When filled, these containers are shipped to a licensed off-site facility for processing and/or disposal. If characterized as Class B or Class C low level

radioactive waste, they can only be disposed of at the Barnwell Low-Level Radioactive Waste Disposal Facility.

The shielded casks with their shipping/disposal containers are located in an outdoor area within the plant radiation controlled area.

Turkey Point

At the Turkey Point Nuclear Plant, there is a single 300 cubic foot spent resin storage tank in the Reactor Auxiliary Building which is used to accumulate spent radioactive waste ion exchanger resin from Units 3 and 4. When the spent resin storage tank is ready to be transferred, the spent ion exchanger resin is sluiced to a shipping/disposal container within a shielded cask. The shipping/disposal container is subsequently shipped to a licensed off-site facility for processing and/or disposal. Additionally, some of the spent ion exchanger resin is sluiced from waste disposal system ion exchangers directly to a shipping/disposal container within a shielded cask prior to being shipped off-site for processing and/or disposal.

At Turkey Point, spent ion exchanger resins with higher levels of radioactivity are accumulated in the spent resin storage tank while the spent ion exchanger resins with lower levels of radioactivity (typically Class A) is accumulated directly in a shipping/disposal container within a shielded cask. Since Class A low level radioactive waste will continue to be disposed of at a licensed low level waste disposal facility in Utah, keeping the spent ion exchanger resin with lower levels of radioactivity segregated from the spent ion exchanger resin with higher levels of radioactivity will minimize the volume of spent ion exchanger resin that will have to be stored on-site after June 30, 2008. The spent ion exchanger resins with higher levels of radioactivity, which are generally characterized as Class B or Class C low level radioactive waste, are sluiced from the spent resin storage tank into a shipping/disposal container within a shielded cask. The shipping/disposal container is subsequently shipped off-site for processing and/or disposal at the Barnwell Low-Level Radioactive Waste Disposal Facility.

The Turkey Point Plant also generates low-level radioactive waste filters that are used to remove suspended particles from primary water systems. The filters that are required to be disposed of at the Barnwell Low-Level Radioactive Waste Disposal Facility are accumulated in a shipping/disposal container within a shielded cask. Other highly contaminated dry solid low level radioactive waste material is similarly collected in a shipping/disposal container within a shielded cask. When filled, these containers are shipped to a licensed off-site facility for processing and/or disposal. If characterized as Class B or Class C low level radioactive waste, they can only be disposed of at the Barnwell Low-Level Radioactive Waste Disposal Facility.

The shielded casks with their shipping/disposal containers are located in the Rad (radioactive) Waste Building.

Q.
How does FPL's current on-site temporary facilities used for the storage of low level radioactive waste differ from the planned facilities for the storage of low level radioactive waste?

A.
FPL's current on-site temporary facilities used for storage of low level radioactive waste were designed for the accumulation of low level radioactive waste prior to shipping it off-site for disposal and have limited capacities and collection times. The planned facilities are for dedicated extended on-site storage facilities to store FPL's Class B and Class C low level radioactive waste that will be unable to be disposed of after June 30, 2008.

Until now, there was no reason to have dedicated extended on-site storage for low level radioactive waste because licensed off-site facilities have been available to FPL for the disposal of Class A, Class B and Class C low level radioactive waste. Due to the requirements imposed by the South Carolina Environmental Protection and Conservation statutes, effective July 1, 2008, FPL will be unable to ship its Class B or Class C low-level radioactive waste for disposal. The planned facilities for the on-site storage of low level radioactive waste will provide on-site storage capability in facilities that will be specifically designed and constructed for extended interim on-site storage of Class B and Class C low level radioactive waste generated by the Turkey Point and St. Lucie nuclear plants.

Q.
What is the total capacity of the temporary facilities FPL currently uses to store low level radioactive waste, both in terms of volume or weight and time (years/months of waste collection)?

A.
The total capacity of the temporary facilities described in the response to Interrogatory No. 48 above that FPL currently uses to accumulate/store low level radioactive waste is as follows:

St. Lucie:
Unit 1 Spent Resin Storage Tank (SRST): 3200 gallons (428 cu-ft.) – Approximately 1 year
Unit 2 Spent Resin Storage Tank (SRST): 3213 gallons (429 cu-ft.) – Approximately 1 year
SRST/Primary Resin shipping/disposal container for spent ion exchanger resin – fill and ship.
Filter shipping/disposal container: 100 cubic feet – Approximately 1 year.
High activity solid waste shipping/disposal container: 110 cubic feet – Approximately 1 – 2 years

Turkey Point:
Units 3 & 4 Spent Resin Storage Tank (SRST): 300 cubic feet – Approximately 1 – 2 years
SRST spent ion exchanger resin shipping/disposal container: 100 cubic feet – Fill and Ship.
Waste disposal demineralizers spent ion exchanger resin shipping/disposal container:
100 cubic feet – Approximately 1 – 2 years
Filter shipping/disposal container: 100 cubic feet – Approximately 1 – 2 years.
High activity solid waste shipping/disposal container: Approximately 1 – 2 years
Four spare shielded casks available to supplement accumulation times/temporary storage of the above low level waste materials.

Q.
What is the total capacity of the planned facilities to store low level radioactive waste, both in terms of volume or weight and time (years/months of waste collection)?

A.
As stated on page 9 of the Testimony of Randall R. Labauve, the planned facilities will be for a period of approximately five years. The five-year storage period will accommodate an estimated 30 - 35 engineered concrete casks, each containing a disposal liner for a total estimated holding capacity of approximately 3,000 - 3500 cubic feet and a disposal volume of approximately 3600 – 4200 cubic feet. (Note: The volume represented by the external dimensions of the disposal container is part of the disposal volume.). FPL is also evaluating the potential for a volume reduction alternative where the low level waste can be shipped off-site for volume reduction processing and then returned to the plant for storage at a reduced volume.

Q.
How frequently does FPL ship its low level radioactive waste to the Barnwell facility?

A.
For the years 2004 – 2006, the Turkey Point Plant and St. Lucie Plant made 19 shipments and 20 shipments, respectively, for Barnwell disposal or approximately 7 shipments per year for each plant. These shipments were made either directly to the Barnwell Low-Level Radioactive Waste Disposal Facility for disposal or to an off-site waste processor for volume reduction prior to disposal at the Barnwell Low-Level Radioactive Waste Disposal Facility.

Q.
How is the cost of FPL current storage facilities for low level radioactive waste recovered by FPL and when was such recovery approved by the Commission?

A.
FPL does not presently have dedicated storage capacity for its Class B/C low-level radioactive waste. As discussed in previous responses, temporary storage is accommodated within existing available space at the plants.

Q.
What is the value of the plant included in FPL rate base associated with on-site low level radioactive waste storage?

A.
There is no dollar value of plant included in FPL rate base that is associated with dedicated storage capability for low level radioactive waste because, as discussed in responses to earlier interrogatories, FPL does not presently have any such facilities. FPL notes that it does have plant value included in rate base associated with waste *processing* equipment, such as Aerated Waste Storage, Waste Gas Disposal, Radwaste Collection and Volume Reduction Systems. This equipment has been and will continue to process low level radioactive waste. This processing will not be avoided once the new on-site low level radioactive waste storage facility is in service.

Q.
What is the level of O&M included in FPL's revenue requirement associated with the on-site low level radioactive waste storage?

A.
There is no O&M included in FPL's revenue requirement associated with on-site low level radioactive *storage*. FPL notes that there is O&M included in FPL's existing revenue requirement associated with the *disposal* of low level radioactive waste. FPL will continue to accrue disposal costs at historical levels, because the low-level waste that will be stored due to the unavailability of the Barnwell facility will ultimately have to be disposed of, at fees that are likely to be at least as high as the current Barnwell fees.

Q.
If it is the case that FPL currently recovers the cost of storage of low level radioactive waste through base rates, why is it appropriate for FPL to recover the costs of low level radioactive waste storage in the ECRC beginning in mid-2009?

A.
N/A. FPL does not recover costs of storing low level radioactive waste through base rates.

Q.
What amount does FPL accrue annually for the disposal of low level radioactive waste?

A.
The amount FPL accrues annually will vary since it is based on the weight and when the low level waste is generated.

The current accruals are as follows:

2007 Year End Forecast:

St. Lucie	$1,506,048
Turkey Point	$888,000

Q.
What types of costs are accrued for disposal of low level radioactive waste (i.e. fees to Barnwell, transportation, personnel, etc.)?

A.
The types of costs accrued for the disposal of low level radioactive waste is as follows:
Disposal Costs
Container Rentals
Inspection Fees
Transportation
Testing
Software
Audit Services

Q.
Show a breakdown of the annual low level radioactive waste accrual by type of cost.

A.
Please see Attachment 1, Pages 1 and 2.

Q.
Show a breakdown of the annual low level radioactive waste accrual by type of cost.

A.
Please see Attachment I, Pages 1 and 2.

Turkey Point

Service Provided	2007 Year-End Forecast
Disposal/Retained Waste	$ 831,651
Duratek/Energy Solutions	$ 455,067
Studsvik/Race	$ 677,690
Other Contractor Services	$ 29,023
Inspection Fees	$ 68,912
Materials/Freight	$ 14,508
Testing	$ 7,183
Forecast/Accrual	$ (420,733)
Container Rental	$ -
Duratek/Energy Solutions	$ -
Studsvik/Race	$ -
Forecast/Accrual	$ -
LLW Total 3762-90	$ -
Radman Software Total 3506-90	$ 15,349
Invoice	$ 15,349
Forecast/Accrual	$ -
WMG Audit Services	$ 41,000
Invoice	$ 39,000
Forecast/Accrual	$ 2,000
	$ 888,000

St Lucie

Service Provided	2007 Year-End Forecast
Disposal/Retained Waste	**$ 1,512,336**
Duratek/Energy Solutions	$ 745,025
Studsvik/Race	$ 506,321
Other Contractor Services	$ 246,485
Materials/Freight	$ -
Testing	$ 14,505
Container Rental	**$ -**
Duratek/Energy Solutions	$ -
Studsvik/Race	$ -
Forecast/Accrual	$ -
LLW Total 3762-90	**$ -**
Radman Software Total	**$ 15,349**
Invoice	$ 15,349
WMG Audit Services	**$ 19,497**
Invoice	$ 19,497
	$ 1,547,181

Q.
What are the other utilities FPL is aware of which do not have access to low level radioactive waste disposal sites after June 30, 2008?

A.
The generators of low level radioactive waste from thirty-six states will lose their capacity to dispose of waste under South Carolina's Environmental Protection and Conservation statute that makes the Barnwell Low-Level Radioactive Waste Management Facility's an Atlantic Compact only facility on July 1, 2008.

There are ninety commercial electrical generating reactor units operating within these thirty-six states. In addition, there are scores of other licensees (e.g., fuel cycle facilities, universities, hospitals, medical facilities, etc.) within the thirty-six states that will lose the ability to dispose of low level radioactive waste at the Barnwell Low-Level Radioactive Waste Disposal Facility.

Q.
What are other utilities which dispose of their low level radioactive waste at the Barnwell facility planning to do with their waste after June 30, 2008?

A.
FPL has no information responsive to this request.

Q.
Does the $12 million cost of the proposed low level radioactive waste storage facilities include the expanded storage discussed on Page 9 of Witness LaBauve's August 31, 2007, direct testimony? If not, please estimate such costs.

A.
No. The estimated cost for expansion of the planned facilities will depend upon the continued rate of low level radioactive waste generation, the length of time that on-site storage will need to be provided and the storage method that will be used. While it is premature to make such a long-range forecast, using an extrapolation of the current estimate of $6 million per site for five years of storage and applying it to the remaining licensed life for Turkey Point and St. Lucie, the future costs could be as much as $65 million.

Q.
What does expanded low level radioactive waste storage described on Page 9 of Witness LaBauve's August 31, 2007 direct testimony entail?

A.
The reference to the expansion of low level radioactive waste storage described on page 9 of Witness Labauve's August 31, 2007 direct testimony is because of the uncertainty about when a new low-level radioactive waste disposal facility will become available. As a result of that uncertainty, FPL must consider the possibility of having to incrementally expand on site storage beyond the initial 5-year period for the planned facilities. However, presently, FPL is not certain that such future expansions will even be required. If such future expansions are required, it is not presently known whether those future expansions will be a simple expansion of the current design for the planned facilities or if a change in the type of facility, design or storage methods will be necessary.

Q.
What sites, if any, are currently under consideration for licensing as a low level radioactive waste disposal facility appropriate for disposal of such waste from Florida nuclear generators?

A.
There currently are no sites under consideration for licensing as a low level radioactive waste disposal facility to accept low level radioactive waste from Turkey Point or St. Lucie.

The Texas-Vermont Low-Level Radioactive Waste Compact is currently developing a low level radioactive waste disposal site in Texas. While the Texas low level radioactive waste disposal facility is expected to take Class A, Class B and Class C low level radioactive waste and would therefore be technically viable for the disposal of FPL's Class B and Class C low level radioactive waste, the Texas-Vermont Low-Level Radioactive Waste Compact facility is currently expected to be licensed to serve only low level waste generators from the States of Vermont and Texas.

Q.
Why did South Carolina Change its environmental laws to restrict the importation of nonregional waste for purposes of disposal after June 30, 2008 ?

A.
FPL has no information responsive to this question.

Florida Power & Light's Responses to

OPC's 1st ROGS Nos. 1 - 14

070007

Q.
Please describe the components and types of equipment that are included in the St. Lucie Cooling System.

A.
The St. Lucie Plant Ocean Cooling Water System consists of a once through cycle, drawing water from the ocean, routing it through the plant and returning the water to the ocean.

The intake side of the Ocean Cooling Water System consists of three velocity cap structures, three intake pipe lines, two head wall structures, one sluice gate valve, stop logs, and an intake canal. The intake components are shared by both units.

The discharge side of the Ocean Cooling Water System consists of a discharge canal, two discharge headwall structures, stop logs, two sluice gate valves and two discharge pipelines, each with a diffuser section. The discharge components are shared by both units.

Supporting electrical and instrument systems associated with operation of the sluice gates, canal temperature, level and structural cathodic protection systems are also part of the Ocean Cooling Water System components.

Q.
Please explain whether the intake and outtake canals at the plant are considered a component of the cooling system as referenced in FPL's petition.

A.
The canals are part of the plant Ocean Cooling Water System, but are not part of the inspection and maintenance activities discussed in the petition.

Q.
How often does FPL inspect and clean the St. Lucie Cooling System?

A.
There are no normally scheduled inspections for the Ocean Cooling Water System components referenced in our petition. The last internal inspection of either the intake or discharge piping was in 1984 when there was an inspection of the discharge piping. Since the 1984 inspection there have been no internal inspections or cleaning of the ocean intake and discharge piping. External inspections of accessible portions of the ocean intake velocity caps and ocean discharge diffuser sections were performed after the hurricanes in 2004.

Unit 2 went into commercial operation in 1983, and at that time the 16 ft intake and discharge pipes were put into service, increasing the flow capacity of the system. Since the start up of Unit 2, at least one unit has been operating at all times, resulting in continuous flow though the system at all times. The continuous flow of warm water in the discharge pipes prevents the build up of marine growth in the discharge piping. Moreover, while some degree of marine growth has occurred in the intake piping, the additional volume of flow provided by the 16 ft pipe is small enough that the marine growth does not impact plant operations. Because of these factors, FPL was able to conclude that on-going pipe inspections and cleaning were not necessary from a plant operations standpoint.

On May 16, 2005, the plant had a "take" of an endangered smalltooth sawfish. These are protected under the Endangered Species Act. Due to the "take" the NRC and NOAA entered into a formal section 7 consultation. The draft Biological Opinion (BO) is a result of that consultation. In order to minimized the impact to endangered species the terms and conditions of the BO required the plant to inspect and clean the pipes. On March 2, 2007, The NRC reinitiated a section 7 consultation to address the increase in "take" for endangered sea turtles at the plant.

Q.
Please provide a description of the types of maintenance work performed on the system. In your response please provide the dates such work was performed since January 1, 2005, and please describe the accounting methodology used to book the costs of such work.

A.
No maintenance work has been performed on the St. Lucie Cooling System since January 1, 2005. The last two times maintenance was performed was in 1991, when repairs were made to the top of the ocean intake velocity caps and in 2003, when repairs to 12-foot diameter ocean discharge piping diffuser section were made. Regular maintenance of the system has been unnecessary from a plant operations standpoint for the same reasons described in the response to Interrogatory No. 3.

Q.
Please explain whether FPL has used a robotic mechanism in the past to inspect the intake pipe of the St. Lucie Cooling System, whether FPL has sought bids for the use of a robotic mechanism in the past, and whether FPL considered the use of a robotic mechanism to inspect the pipes in response to Nona's letter regarding sawfish take concerns.

A.
There has been no previous need for robotic mechanisms to inspect the intake piping, and so no bids have been sought prior to preparation of cost estimates associated with the petition.

Q.
Please describe whether FPL has ever performed an inspection of the St. Lucie Cooling System, either when water was flowing through the intake pipes or not flowing through the intake pipes.

A.
Yes. There were inspections of the interior of the ocean intake and discharge piping performed. The last inspection was performed in 1984. The inspections were performed during refueling outage(s) with minimal flow in the pipes. For the reasons explained in the response to Interrogatory No. 3, there has been no need for regular inpsections from a plant operations standpoint.

Q.
Please describe all types of maintenance performed on the St. Lucie Cooling System during the normal planned outages to the generating plant.

A.
Since 1984 no maintenance has been performed on the St. Lucie Ocean Cooling Water System during normal planned outages. The last two times maintenance was performed was in 1991, when repairs were made to the top of the ocean intake velocity caps and in 2003, when repairs to 12-foot diameter ocean discharge piping diffuser section were made. This maintenance was performed outside of a plant outage.

Unit 2 went into commercial operation in 1983, and at that time the 16 ft intake and discharge pipes were put into service, increasing the flow capacity of the system. Additionally, because of the start up of Unit 2, at least one unit is operating at all times, resulting in continuous flow though the system at all times. The continuous flow of warm water in the discharge pipes prevents the build up of marine growth in the discharge piping. The additional volume of flow provided by the 16 ft pipe on the intake piping is such that the marine growth does not impact plant operations. These facts attributed to the elimination of on-going pipe inspections and cleaning.

On May 16, 2005, the plant had a "take" of an endangered smalltooth sawfish. These are protected under the Endangered Species Act. Due to the "take" the NRC and NOAA entered into a formal section 7 consultation. The draft Biological Opinion (BO) is a result of that consultation. In order to minimized the impact to endangered species the terms and conditions of the BO required the plant to inspect and clean the pipes. On March 2, 2007, The NRC reinitiated a section 7 consultation to address the increase in "take" for endangered sea turtles at the plant.

Q.
Please describe all inspections that took place in the St. Lucie Cooling System in the last two planned outages of the St. Lucie plant.

A.
The last two refueling outages took place in October 2005 (SL1-20) and April 2006 (SL2-16). No inspections were performed on the St. Lucie Ocean Cooling Water System during the last two outages.

Q.
Please describe all other inspections that have been made to the St. Lucie Cooling System since the last planned outage prior to 2007.

A.
The last planned outage was April 2006 (SL2-16). Since this outage in April, external inspections of the velocity caps and pipe diffusers have been performed have been performed by an underwater dive team to inspect for potential damage resulting from the 2005 hurricanes. Because of poor water quality immediately following the 2005 hurricane season, this inspection could not be performed until March 2006. Flow velocities at the velocity caps and discharge diffusers were measured. Marine growth on the velocity caps prevented a accurate assessment of the structural condition, and so another inspection which included some limited cleaning of the exterior surface of the velocity was recently completed in February 2007. Additionally, as part of post-hurricane inspection, a benthic survey is being performed for the ocean floor surrounding the velocity caps and diffusers, to determine the extent of erosion as a result of the hurricanes. The final report from these inspections is scheduled to be received later this month.

Q.
Please state the number of instances that FPL has inspected the intake pipe, removed any debris, or repaired any structural obstruction to the intake pipe of St. Lucie Cooling System between since the installation of the intake pipe.

A.
Unit 1 went into commercial operation in 1976. Cooling water was provided by only 2-12 foot diameter pipes and was discharged through only 1-12 foot diameter discharge pipe. The first successful cleaning of these pipes was in 1979, when a mechanical scraper pig was used for cleaning of the pipes. During the construction and start-up of Unit 2 in 1983, 16 ft diameter intake and discharges pipes were constructed and put into service to provide a total of three intake pipes and two discharge pipes. Between 1976 and 1984, cleaning and inspection work took place during plant outages. The last pipe cleaning took place in 1983, when approximately 75% of the south 12 foot diameter intake pipe was cleaned.

No documented internal inspections of the intake pipes have been found since the last partial cleaning of the south 12 foot diameter intake pipe in 1983. The last documented inspection of either the intake or discharge pipes since the start-up of Unit 2 was an inspection of the 16 foot discharge pipe in 1984.

The only repair of a structural obstruction to the intake piping was in 1991, when repairs were made to the top of the ocean intake velocity caps. This maintenance was performed outside of a plant outage.

As explained in response to Interrogatory No. 3, regular inspections and maintenance of the system have not been necessary from a plant operations standpoint.

Q.
Please describe all repairs made to the St. Lucie Cooling System that were made as a result of the 2004 or 2005 hurricane seasons.

A.
No repairs were required to be made as a result of the 2004 or 2005 hurricane seasons. External inspections have not identified any structural damage. Assessments of ocean bottom and beach erosion are still on-going.

Q.
Please describe the regular inspection and maintenance requirements mandated by the Nuclear Regulatory Commission regarding the St. Lucie Cooling System. Please include the time frames in which any inspections are required.

A.
No regular inspection and maintenance of the St. Lucie Ocean Cooling Water System is mandated by the NRC. Until the requirements associated with the Endangered Species Act, as documented in NOAA's letter concerning sawfish take, no inspections were mandated associated with operational issues.

Q.
Please explain why the methods of inspection that currently take place during planned outages are not sufficient for the terms of the Biological Order stated in NOAA's December 19, 2006 letter.

A.
Since 1984, there have been no internal inspections of the piping and none are normally required to be performed. Please see FPL's response to Interrogatory No. 3.

Q.
Please explain whether the costs associated with any inspections or repairs to the St. Lucie Cooling System addressed in the above questions have been recovered through the fuel or environmental clause, or through any storm recovery charge.

A.
Post hurricane inspections of the external portions of the intake velocity caps and discharge diffusers to determine the structural integrity have been submitted through the storm recovery charge.

Other than the recent post hurricane inspections noted above, none of the inspections or repairs to the St. Lucie Ocean Cooling Water System addressed above has been recovered through the fuel or environmental clause or through any storm recovery charge.

Florida Power & Light's Responses to

Staff's 2nd PODS Nos. 2 & 3

070007

Q. **Please provide Tables 2 and 3 referenced in Rule 62-550.310(3).**

A. Document responsive to this request is provided as Bates No. ECRC 07-007.

TABLE 2
MAXIMUM RESIDUAL DISINFECTANT LEVELS

FEDERAL CONTAMINANT ID NUMBER	DISINFECTANT RESIDUAL	MRDL (mg/L)
1012	Chlorine	4.0 (as Cl_2)
1006	Chloramines	4.0 (as Cl_2)
1008	Chlorine Dioxide	0.8 (as ClO_2)

Abbreviations Used: mg/L = milligrams per liter;
MRDL = maximum residual disinfectant level.

TABLE 3
STAGE 1 MAXIMUM CONTAMINANT LEVELS FOR DISINFECTION BYPRODUCTS

FEDERAL CONTAMINANT ID NUMBER	CONTAMINANT	MCL (mg/L)
2950	Total Trihalomethanes (TTHM)	0.080
2456	Haloacetic Acids (Five) (HAA5)	0.060
1011	Bromate	0.010
1009	Chlorite	1.0

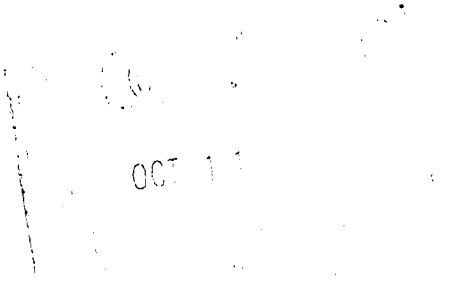
Abbreviations Used: MCL = maximum contaminant level;
mg/L = milligrams per liter.

Q.

Please provide a copy of the Department of Environmental Protection's October 17, 2006 letter to FPL regarding the FPL Martin Plant nontransient noncommunity public water system, PWS #4431748.

A.

Document responsive to this request is provided as Bates No. ECRC 07-008.



Department of Environmental Protection

Southeast District
400 N. Congress Avenue, Suite 200
West Palm Beach, Florida 33401

Jeb Bush
Governor

Colleen M. Castille
Secretary

OCT 17 2006

Harold A. Frediani, Jr., P.E., P.H.
Golder Associates, Inc.
3730 Chamblee Tucker Road
Atlanta, GA 30341
Fax (770) 934-9476

SUBJECT: Consent Order in OGC File No.: 06-0744
Florida Power & Light Martin Plant PWS #4431748

Dear Mr. Frediani:

The Department acknowledges receipt of an engineering evaluation, including a proposed corrective action plan (Plan), as required by paragraph 5a of the referenced Consent Order. So that the Department may complete its review of the Plan, clarification is needed regarding the proposed pilot plant study.

The Plan indicates that a pilot study will be conducted from January 31, 2007 through September 30, 2007. It was initially indicated that water from the pilot plant would be discharged to waste; however, it is the Department's understanding that this plan has changed and it is now proposed that the water from the pilot plant will discharge to the public water system rather than discharging to waste.

- Please be aware that if the water from the pilot plant discharges to the drinking water system and the pilot study lasts more than three months, a Department permit will be required pursuant to Rule 62-555.520(1)(b), Florida Administrative Code (FAC). If a permit is required for the pilot study, the proposed compliance schedule will need to be revised to incorporate the permitting timeframes for the pilot study.

- If the water from the pilot plant will discharge to the public water system and the pilot study lasts less than three months, no permit is required, but the supplier of water must provide the information required by Rule 62-555.520(1)(b), FAC, and obtain written Department approval prior to beginning the pilot study.

Please respond in writing within 30 days of your receipt of this letter confirming how the pilot study will be conducted, including all applicable timelines, and, if necessary, include a revised compliance schedule.

If you have any questions regarding this matter, please contact Michele Owens of this office at (561) 681-6700 or via email at Michele.Owens@dep.state.fl.us.

Sincerely,

Todd R. Brown, C.P.M.
Environmental Manager
Water Facilities Compliance/Enforcement Program

TRB/mo

cc: Willie Welch – FPL, P.O. Box 176, Indiantown, FL, 34956 Willie_Welch@FPL.com
Jerry Toney – DEP/PSL Jerry.Toney@dep.state.fl.us
Jose Calas – DEP/WPB Jose.Calas@dep.state.fl.us

ECRC 07-008

Florida Power & Light's Responses to

Staff's 3rd PODS Nos. 4 & 11

070007

Q.
Provide the initial and final briefs FPL filed with the 3rd Circuit Court of Appeals regarding FPL's legal challenge to FDEP's CAIR implementation rules.

A.
Documents responsive to this request are provided as Bates Nos. ECRC 07-009 through ECRC 07-0086.

THIRD DISTRICT COURT OF APPEAL
STATE OF FLORIDA

CASE NO. 3D07-840

2007 JUN -8 AM 11:33
FILED
DISTRICT COURT OF APPEAL
CLERK, THIRD DISTRICT

FLORIDA POWER & LIGHT COMPANY,

LT DOAH Case No. 06-287IRP

Petitioner/Appellant,

v.

DEPARTMENT OF ENVIRONMENTAL PROTECTION,

Respondent/Appellee,

_____/

APPELLANT'S INITIAL BRIEF

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example." It also abdicated DEP's responsibility to make a rational choice based on statutory objectives rather than the results of a popularity contest.

Finally, DEP disclosed for the first time at the rule-challenge hearing that it viewed the FAHI method as "equitable" because it allocated allowances based on the differing "needs" of coal-, gas- and oil-fired EGUs. RA1, Tr. 719-27, 731-32 (Rogers). As DEP acknowledged, this rationale amounts to recognizing that coal-fired EGUs pollute more than other EGUs and then rewarding them for doing so. RA1, Tr. 735-36 (Rogers); RA2, FPL Ex. 40 (George Depo) pp. 42-43.

In sum, at the outset of its rulemaking DEP raised valid, substantial concerns over allocating allowances with the FAHI method, which it has never disavowed. In spite of these concerns, DEP determined to utilize fuel adjustment factors to favor coal-fired EGUs, and adopted the Challenged Provisions without ever articulating a legitimate, logical rationale for doing so.

3. *Assessing the Impact of the Challenged Provisions.*

DEP has the power and duty under section 403.061(35) of the Florida Statutes to

> Exercise the duties, powers, and responsibilities required of the state under the federal Clean Air Act, 42 U.S.C. ss. 7401 et seq. The department shall implement the programs required under that act in conjunction with its other powers and duties. Nothing in this subsection shall be construed to repeal or supersede any of the department's existing rules.

Because CAIR implements the CAA, DEP was thus obligated to enact rules enforcing CAIR in Florida, and in fact cited this paragraph in the Proposed Rules as the law that it was implementing. However, nothing in the CAIR regulations required the DEP to utilize the FAHI method or its fuel adjustment factors. That action was left to the discretion of the individual states and therefore was not "required of the state" under the CAA.

The Proposed Rules fulfill Florida's CAIR obligation, with or without the Challenged Provisions. As discussed above, EPA expressly advised the CAIR States that they were not obligated or even encouraged to allocate NOx allowances using the FAHI method. Thus, DEP's obligation to implement CAA programs in Florida did not require it to adopt the Challenged Provisions. Those provisions would therefore be proper only to the extent they implement DEP's *other* statutory powers and duties. However, DEP never identified any other power or duty that would justify the Challenged Provisions.

Moreover, two of DEP's bedrock, fundamental duties are to avoid imposing "regulatory costs on [a] regulated person, county, or city which could be reduced by the adoption of less costly alternatives that substantially accomplish the statutory objectives" (§120.52(8)(f), Fla. Stat. (2006); *see also* §120.541, Fla. Stat. (2006)), and to regulate air emissions in a way that protects air quality both within Florida and regionally (*see* §§403.021(3)-(4) and 403.031(9), Fla. Stat. (2006)).

As will be seen, far from implementing its powers and duties, the decision to include the Challenged Provisions and allocate allowances on a FAHI base utterly failed to fulfill these obligations.

a. The Lowest Cost Regulatory Alternative.

Throughout the rulemaking process and continuing in the rule challenge, FPL demonstrated to DEP that the Challenged Provisions would make it substantially more expensive for FPL to comply with the Proposed Rules. In other words, from FPL's perspective, the Proposed Rules without the Challenged Provisions clearly would be a "less costly alternative that substantially accomplishes the statutory objectives" as envisioned by sections 120.52(8)(f) and 120.541. The Challenged Provisions result in a shift of approximately 7,000 allowances away from FPL to other utilities in Florida. RA1, Tr. 79 (LaBauve) and 264 (Butts). Under DEP's estimates of allowance prices, this will increase FPL's compliance costs by $11 million to $25 million each year. RA1, Tr. 109-10 (LaBauve).

DEP never denied that FPL will incur these additional regulatory costs because of the Challenged Provisions. It argued instead that a shift of costs away from FPL would result in other EGUs having to pay the higher costs, with no net change in overall compliance costs for Florida.

DEP was properly concerned about the impact that different allowance allocation methods could have on overall CAIR compliance costs. It hired Dr. Paul Sotkiewicz, an economist at the University of Florida, to assist in evaluating this issue. Dr. Sotkiewicz developed a computer simulation model to evaluate the compliance strategies of Florida's EGUs under various scenarios, including different allocations of allowances, and to calculate the resulting compliance costs. R. 1109.

Unfortunately, however, the Sotkiewicz model proved to be structurally incapable of simulating changes in compliance strategy or in overall compliance costs resulting from different allowance allocations. This is because the model assumed as an input that allowances would be freely traded among EGUs and, as a result, that the EGUs would behave no differently regardless of whether they were allocated too few, too many or just enough allowances to meet their needs. By making this assumption as a modeling input, the Sotkiewicz model contained no computational mechanism that could simulate different compliance strategies based on different allowance allocations. In other words, insofar as EGU compliance strategies are concerned, the model's output was simply a circular restatement of its input.[6]

[6] RA1, Tr. 423 (Landon); RA2, FPL Ex. 42 (Stratis Depo) pp. 87-88, FPL Ex. 54 pp. 3-4. The Sotkiewicz model is capable of showing different compliance *costs* for individual EGUs based on different allowance allocations (different needs to

By virtue of FPL's comments during the rulemaking and FPL's positions and evidence during the rule challenge, DEP and Dr. Sotkiewicz were well aware of this deficiency in the model. However, neither DEP nor Dr. Sotkiewicz ever revised the model so that it could simulate changes in compliance strategy resulting from different allowance allocations. Nor did they conduct any analyses to determine what impact changed compliance strategies would have on overall CAIR compliance costs.[7] FPL's witnesses testified at the rule challenge hearing that, under reasonable assumptions, the allocation of allowances *would* affect EGUs' compliance decisions. RA1, Tr. 203-05 (Hampp) and 408-411, 426-30 (Landon); RA2, FPL Exs. 54 and 55.

b. Impact of the Challenged Provisions on Air Quality.

DEP also had good reason to be concerned that the Challenged Provisions would be inconsistent with its duty to protect air quality both within Florida and

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buy and sell allowances). What the model cannot address, however, is whether (for example) an EGU that is allocated enough allowances to cover its current NOx emissions will be less likely to install emission controls than it would be if it were allocated fewer allowances. That question is the crux of the issue presented to DEP and one that, illogically, DEP failed even to consider.

[7] RA1, Tr. 513-14 (Landon) and 862-63 (Sotkiewicz); RA2, FPL Ex. 54 pp. 3-4. DEP claimed that modeling changes in compliance outcome would be too difficult and require it to model the entire 28-state CAIR region. However, there was no dispute that some analysis of these matters could have been accomplished by so-called "sensitivity analyses" which look at the impact of changed assumptions on the modeling result. FPL demonstrated at the final hearing that even relatively simple sensitivity analyses can show changing allocation systems changes the total cost.

regionally. FPL raised this concern in both the rulemaking proceeding and in its positions and evidence in the rule challenge. Notably, DEP never claimed that there was any benefit to air quality, either local or interstate, from the Challenged Provisions.

The concern over the air quality impacts of the Challenged Provisions stems from the fact that the coal-fired EGUs that benefit from the Challenged Provisions are located predominantly in north Florida, while the oil- and gas-fired EGUs tend to be located more southerly. For Florida, the downwind areas that CAIR is intended to protect are all located in Georgia and Alabama, meaning that they are much closer to the coal-fired EGUs in north Florida than to Florida's oil- and gas-fired EGUs. RA1, Tr. 192-93 (Hampp).

Emissions from EGUs tend to affect nearby areas more than areas that are farther away. RA1, Tr. 179 (Hampp). Thus, if Florida's coal-fired EGUs were to use some or all of the extra NOx allowances they receive under the Challenged Provisions to emit more NOx, then those emissions could be reasonably expected to have an adverse impact on air quality in the very areas CAIR is designed to protect. This impact would not be fully offset by reduced emissions from oil- and gas-fired EGUs, because they are located farther away from the protected areas. *Id.* Simply put, from the perspective of the downwind impacts that CAIR is intended to address, the emissions from the coal-fired EGUs matter more because

ECRC 07-0028 070007-Hearing Exhibit 000233

they are closer to the protected areas. DEP nonetheless failed to conduct any analysis of the environmental impacts of its allocation system choices.

Had DEP and Dr. Sotkiewicz developed an economic model that was capable of simulating changes in compliance strategy resulting from different allowance allocations, DEP would have been able to evaluate those impacts. Again, however, the Sotkiewicz model is structurally incapable of providing useful insight. And again DEP, rather than trying to remedy this deficiency, simply hid its head in the sand.

4. **Deficiencies in the Final Order.**

In many respects the Final Order is thorough and carefully reasoned. There are, however, three respects in which the Final Order is fundamentally and fatally deficient. Those deficiencies are the subject of this appeal.

a. <u>The ALJ Misunderstood the Extent of DEP's Discretion Under CAIR to Choose Whatever Allowance Allocation Method Best Meets Florida's Needs.</u>

As shown by the discussion above, CAIR neither determines how to distribute NOx allowances within the CAIR States that participate in the cap and trade program nor directs (or even encourages) those states as to how they should make the allocation. To the contrary, EPA expressly informed the states that they could allocate the allowances however they wish. This point was fundamentally misunderstood by the ALJ -- who equated EPA's *illustrative* model allocation

Q.
Provide documents showing FPL's evaluation of the 800 MW unit cycling project is cost effective.

A.
The attached documents, Bates numbered ECRC 07-00377 through ECRC 07-00383 provide current estimates of the net present value of implementing the 800 MW cycling project. The net present value savings over 20 years were calculated to be $780 million ($264 million were attributable to the emissions improvement and $516 million to fuel savings).

Reliable Economic Dispatch of 800 MW Units

Results - Cash Flow Analysis

	1 2007	2 2008	3 2009	4 2010	5 2011	6 2012
Operating Savings						
Fuel Savings	0.00	0.00	97,100,000.00	61,600,000.00	68,000,000.00	102,900,000.00
Emission Cost Savings	0.00	0.00	12,538,264.68	25,824,869.66	29,134,332.40	40,651,766.23
Total Operating Savings	0.00	0.00	109,638,264.68	87,424,869.66	97,134,332.40	143,551,766.23
Operating Costs						
Operating Cost Initial Investment	0.00	1,464,597.36	2,298,419.54	1,372,384.37	0.00	0.00
Maintenance Cost (Vom Cycle)	0.00	0.00	0.00	13,157,018.27	11,728,528.42	12,496,331.44
On-Going O&M Costs (Nde Inspections)	0.00	0.00	0.00	0.00	647,050.72	219,859.40
Tax Depreciation - No Const.	0.00	1,027,408.50	3,785,314.19	6,577,051.67	7,351,981.29	6,800,563.15
Tax Depreciation - Const.	0.00	0.00	0.00	0.00	0.00	0.00
Property Taxes & Insurance	0.00	509,868.59	1,382,490.48	1,944,697.09	1,847,571.35	1,750,522.58
Total Project Costs	0.00	3,001,874.46	7,466,224.21	23,051,151.40	21,576,131.79	21,267,276.58
Net Project Savings (Cost)	0.00	(3,001,874.46)	102,172,040.47	64,373,718.27	75,558,200.62	122,284,489.65
Income Taxes	0.00	(1,053,657.94)	35,862,386.21	22,595,175.11	26,520,928.42	42,921,855.87
After Tax Savings (Cost)	0.00	(1,948,216.52)	66,309,654.27	41,778,543.15	49,037,272.20	79,362,633.78
Add back Depreciation	0.00	1,027,408.50	3,785,314.19	6,577,051.67	7,351,981.29	6,800,563.15
After Tax Operating Cash Flows	0.00	(920,808.02)	70,094,968.45	48,355,594.83	56,389,253.49	86,163,196.93
Present Value @ 8.4%	0.00	(849,446.08)	59,651,352.07	37,961,809.11	40,837,884.82	57,564,590.91
Cumulative Present Value	0.00	(849,446.08)	58,801,905.99	96,763,715.10	137,601,599.92	195,166,190.83
CAPITAL INVESTMENTS:						
Capital Investment -No Const	0.00	27,397,560.09	48,199,581.94	33,818,367.08	0.00	0.00
Capital Investment - Construction	0.00	0.00	0.00	0.00	0.00	0.00
Investment in Land	0.00	0.00	0.00	0.00	0.00	0.00
Total Capital Investments	0.00	27,397,560.09	48,199,581.94	33,818,367.08	0.00	0.00
Present Value @ 8.4%	0.00	25,274,269.48	41,018,211.37	26,549,283.49	0.00	0.00
Cumulative Present Value	0.00	25,274,269.48	66,292,480.85	92,841,764.34	92,841,764.34	92,841,764.34
Present Value Total Cash Flows	0.00	(26,123,715.56)	18,633,140.70	11,412,525.62	40,837,884.82	57,564,590.91
Cumulative Present Value	0.00	(26,123,715.56)	(7,490,574.86)	3,921,950.76	44,759,835.58	102,324,426.49
Net Present Value	780,763,314					
Discounted Pay-Back Period	3					
Internal Rate of Return of Cash Flows*	110%					
After Tax Operating Cash Flows	0.00	(28,318,368.11)	21,895,386.51	14,537,227.75	56,389,253.49	86,163,196.93

** IRR IS IRRELEVANT IF THERE ARE NO OPERATING SAVINGS ASSOCIATED WITH THE PROJECT*

ECRC 07-00377

Reliable Economic Dispatch of 800 MW Units

Results - Cash Flow Analysis

	7 2013	8 2014	9 2015	10 2016	11 2017	12 2018
Operating Savings						
Fuel Savings	90,400,000.00	108,300,000.00	97,600,000.00	113,900,000.00	123,000,000.00	150,600,000.00
Emission Cost Savings	40,549,952.27	47,313,719.66	48,832,331.32	57,007,794.53	57,176,919.93	70,504,029.17
Total Operating Savings	130,949,952.27	155,613,719.66	146,432,331.32	170,907,794.53	180,176,919.93	221,104,029.17
Operating Costs						
Operating Cost Initial Investment	0.00	0.00	0.00	0.00	0.00	0.00
Maintenance Cost (Vom Cycle)	11,821,733.87	11,782,655.11	14,378,122.14	12,594,746.24	13,777,270.07	13,183,471.04
On-Going O&M Costs (Nde Inspections)	967,636.23	228,147.04	790,494.38	549,702.88	724,780.48	246,266.71
Tax Depreciation - No Const.	6,290,563.70	5,818,583.95	5,382,213.93	5,055,106.01	4,902,137.06	4,881,638.02
Tax Depreciation - Const.	0.00	0.00	0.00	0.00	0.00	0.00
Property Taxes & Insurance	1,653,430.33	1,556,262.32	1,459,003.20	1,361,887.01	1,264,944.77	1,168,149.45
Total Project Costs	20,733,364.12	19,385,648.42	22,009,833.66	19,561,442.15	20,669,132.38	19,479,525.22
Net Project Savings (Cost)	110,216,588.15	136,228,071.24	124,422,497.66	151,346,352.38	159,507,787.55	201,624,503.95
Income Taxes	38,686,022.44	47,816,053.01	43,672,296.68	53,122,569.69	55,987,233.43	70,770,200.89
After Tax Savings (Cost)	71,530,565.71	88,412,018.23	80,750,200.98	98,223,782.70	103,520,554.12	130,854,303.06
Add back Depreciation	6,290,563.70	5,818,583.95	5,382,213.93	5,055,106.01	4,902,137.06	4,881,638.02
After Tax Operating Cash Flows	77,821,129.41	94,230,602.19	86,132,414.92	103,278,888.70	108,422,691.18	135,735,941.08
Present Value @ 8.4%	47,962,064.79	53,574,611.72	45,175,234.25	49,970,312.94	48,393,543.06	55,889,319.11
Cumulative Present Value	243,128,255.62	296,702,867.34	341,878,101.59	391,848,414.53	440,241,957.58	496,131,276.69
CAPITAL INVESTMENTS:						
Capital Investment -No Const	0.00	0.00	0.00	0.00	0.00	0.00
Capital Investment - Construction	0.00	0.00	0.00	0.00	0.00	0.00
Investment in Land	0.00	0.00	0.00	0.00	0.00	0.00
Total Capital Investments	0.00	0.00	0.00	0.00	0.00	0.00
Present Value @ 8.4%	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Present Value	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34
Present Value Total Cash Flows	47,962,064.79	53,574,611.72	45,175,234.25	49,970,312.94	48,393,543.06	55,889,319.11
Cumulative Present Value	150,286,491.28	203,861,103.00	249,036,337.24	299,006,650.19	347,400,193.24	403,289,512.35
Net Present Value						
Discounted Pay-Back Period.						
Internal Rate of Return of Cash Flows*						
After Tax Operating Cash Flows	77,821,129.41	94,230,602.19	86,132,414.92	103,278,888.70	108,422,691.18	135,735,941.08

** IRR IS IRRELEVANT IF THERE ARE NO OPERATING SAVINGS ASSOCIATED WITH*

FCRC 07-00278

Reliable Economic Dispatch of 800 MW Units

Results - Cash Flow Analysis

	13 2019	14 2020	15 2021	16 2022	17 2023	18 2024
Operating Savings						
Fuel Savings	138,600,000.00	174,700,000.00	185,500,000.00	206,500,000.00	250,900,000.00	251,800,000.00
Emission Cost Savings	71,861,182.99	80,369,440.40	74,587,209.44	81,542,517.92	83,092,903.14	85,279,326.42
Total Operating Savings	210,461,182.99	255,069,440.40	260,087,209.44	288,042,517.92	333,992,903.14	337,079,326.42
Operating Costs						
Operating Cost Initial Investment	0.00	0.00	0.00	0.00	0.00	0.00
Maintenance Cost (Vom Cycle)	12,819,734.49	11,569,499.66	11,914,187.26	11,288,524.97	11,071,400.66	10,505,263.05
On-Going O&M Costs (Nde Inspections)	1,084,237.73	255,822.10	782,166.69	616,412.83	920,773.03	276,096.49
Tax Depreciation - No Const.	4,881,507.86	4,881,638.02	4,881,507.86	4,881,638.02	4,881,507.86	4,881,638.02
Tax Depreciation - Const.	0.00	0.00	0.00	0.00	0.00	0.00
Property Taxes & Insurance	1,071,324.85	974,383.72	877,377.67	780,484.91	683,603.26	586,771.40
Total Project Costs	19,856,804.92	17,681,343.51	18,455,239.48	17,567,060.73	17,557,284.81	16,249,768.97
Net Project Savings (Cost)	190,604,378.07	237,388,096.89	241,631,969.96	270,475,457.19	316,435,618.33	320,829,557.46
Income Taxes	66,902,136.70	83,323,222.01	84,812,821.45	94,936,885.47	111,068,902.03	112,611,174.67
After Tax Savings (Cost)	123,702,241.37	154,064,874.88	156,819,148.50	175,538,571.71	205,366,716.29	208,218,382.79
Add back Depreciation	4,881,507.86	4,881,638.02	4,881,507.86	4,881,638.02	4,881,507.86	4,881,638.02
After Tax Operating Cash Flows	128,583,749.22	158,946,512.90	161,700,656.36	180,420,209.74	210,248,224.15	213,100,020.81
Present Value @ 8.4%	48,841,249.82	55,695,282.63	52,269,207.34	53,800,466.12	57,836,221.85	54,077,647.99
Cumulative Present Value	544,972,526.51	600,667,809.14	652,937,016.48	706,737,482.60	764,573,704.45	818,651,352.44
CAPITAL INVESTMENTS:						
Capital Investment -No Const	0.00	0.00	0.00	0.00	0.00	0.00
Capital Investment - Construction	0.00	0.00	0.00	0.00	0.00	0.00
Investment in Land	0.00	0.00	0.00	0.00	0.00	0.00
Total Capital Investments	0.00	0.00	0.00	0.00	0.00	0.00
Present Value @ 8.4%	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Present Value	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34
Present Value Total Cash Flows	48,841,249.82	55,695,282.63	52,269,207.34	53,800,466.12	57,836,221.85	54,077,647.99
Cumulative Present Value	452,130,762.17	507,826,044.80	560,095,252.14	613,895,718.26	671,731,940.11	725,809,588.10
Net Present Value						
Discounted Pay-Back Period						
Internal Rate of Return of Cash Flows*						
After Tax Operating Cash Flows	128,583,749.22	158,946,512.90	161,700,656.36	180,420,209.74	210,248,224.15	213,100,020.81

** IRR IS IRRELEVANT IF THERE ARE NO OPERATING SAVINGS ASSOCIATED WITH*

ECRC 07-00379

Reliable Economic Dispatch of 800 MW Units

Results - Cash Flow Analysis

	19 2025	20 2026	21 2027	22 2028	23 2029	24 2030
Operating Savings						
Fuel Savings	275,900,000.00	0.00	0.00	0.00	0.00	0.00
Emission Cost Savings	88,733,129.55	0.00	0.00	0.00	0.00	0.00
Total Operating Savings	364,633,129.55	0.00	0.00	0.00	0.00	0.00
Operating Costs						
Operating Cost Initial Investment	0.00	0.00	0.00	0.00	0.00	0.00
Maintenance Cost (Vom Cycle)	10,845,879.46	0.00	0.00	0.00	0.00	0.00
On-Going O&M Costs (Nda Inspections)	1,216,318.63	0.00	0.00	0.00	0.00	0.00
Tax Depreciation - No Const.	4,881,507.86	4,881,638.02	4,881,507.86	4,270,398.45	2,583,970.03	754,487.77
Tax Depreciation - Const.	0.00	0.00	0.00	0.00	0.00	0.00
Property Taxes & Insurance	490,173.93	393,799.44	297,447.20	176,261.12	60,370.68	0.00
Total Project Costs	17,433,879.88	5,275,437.46	5,178,955.05	4,446,659.57	2,644,340.71	754,487.77
Net Project Savings (Cost)	347,199,249.67	(5,275,437.46)	(5,178,955.05)	(4,446,659.57)	(2,644,340.71)	(754,487.77)
Income Taxes	121,866,936.64	(1,851,678.55)	(1,817,813.22)	(1,560,777.51)	(928,163.59)	(264,825.21)
After Tax Savings (Cost)	225,332,313.04	(3,423,758.91)	(3,361,141.83)	(2,885,882.06)	(1,716,177.12)	(489,662.56)
Add back Depreciation	4,881,507.86	4,881,638.02	4,881,507.86	4,270,398.45	2,583,970.03	754,487.77
After Tax Operating Cash Flows	230,213,820.90	1,457,879.11	1,520,366.03	1,384,516.39	867,792.91	264,825.21
Present Value @ 8.4%	53,893,007.37	314,839.53	302,888.39	254,448.15	147,124.17	41,418.46
Cumulative Present Value	872,544,359.81	872,859,199.35	873,162,087.74	873,416,535.89	873,563,660.06	873,605,078.52
CAPITAL INVESTMENTS:						
Capital Investment -No Const	0.00	0.00	0.00	0.00	0.00	0.00
Capital Investment - Construction	0.00	0.00	0.00	0.00	0.00	0.00
Investment in Land	0.00	0.00	0.00	0.00	0.00	0.00
Total Capital Investments	0.00	0.00	0.00	0.00	0.00	0.00
Present Value @ 8.4%	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Present Value	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34
Present Value Total Cash Flows	53,893,007.37	314,839.53	302,888.39	254,448.15	147,124.17	41,418.46
Cumulative Present Value	779,702,595.47	780,017,435.00	780,320,323.40	780,574,771.55	780,721,895.71	780,763,314.18
Net Present Value						
Discounted Pay-Back Period						
Internal Rate of Return of Cash Flows*						
After Tax Operating Cash Flows	230,213,820.90	1,457,879.11	1,520,366.03	1,384,516.39	867,792.91	264,825.21

** IRR IS IRRELEVANT IF THERE ARE NO OPERATING SAVINGS ASSOCIATED WITH*

ECRC 07-00380

Reliable Economic Dispatch of 800 MW Units

Results - Cash Flow Analysis

	25 2031	26 2032	27 2033	28 2034	29 2035	30 2036
Operating Savings						
Fuel Savings	0.00	0.00	0.00	0.00	0.00	0.00
Emission Cost Savings	0.00	0.00	0.00	0.00	0.00	0.00
Total Operating Savings	0.00	0.00	0.00	0.00	0.00	0.00
Operating Costs						
Operating Cost Initial Investment	0.00	0.00	0.00	0.00	0.00	0.00
Maintenance Cost (Vom Cycle)	0.00	0.00	0.00	0.00	0.00	0.00
On-Going O&M Costs (Nde Inspections)	0.00	0.00	0.00	0.00	0.00	0.00
Tax Depreciation - No Const.	0.00	0.00	0.00	0.00	0.00	0.00
Tax Depreciation - Const.	0.00	0.00	0.00	0.00	0.00	0.00
Property Taxes & Insurance	0.00	0.00	0.00	0.00	0.00	0.00
Total Project Costs	0.00	0.00	0.00	0.00	0.00	0.00
Net Project Savings (Cost)	0.00	0.00	0.00	0.00	0.00	0.00
Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00
After Tax Savings (Cost)	0.00	0.00	0.00	0.00	0.00	0.00
Add back Depreciation	0.00	0.00	0.00	0.00	0.00	0.00
After Tax Operating Cash Flows	0.00	0.00	0.00	0.00	0.00	0.00
Present Value @ 8.4%	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Present Value	873,605,078.52	873,605,078.52	873,605,078.52	873,605,078.52	873,605,078.52	873,605,078.52
CAPITAL INVESTMENTS:						
Capital Investment -No Const	0.00	0.00	0.00	0.00	0.00	0.00
Capital Investment - Construction	0.00	0.00	0.00	0.00	0.00	0.00
Investment in Land	0.00	0.00	0.00	0.00	0.00	0.00
Total Capital Investments	0.00	0.00	0.00	0.00	0.00	0.00
Present Value @ 8.4%	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Present Value	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34
Present Value Total Cash Flows	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Present Value	780,763,314.18	780,763,314.18	780,763,314.18	780,763,314.18	780,763,314.18	780,763,314.18
Net Present Value						
Discounted Pay-Back Period						
Internal Rate of Return of Cash Flows*						
After Tax Operating Cash Flows	0.00	0.00	0.00	0.00	0.00	0.00

** IRR IS IRRELEVANT IF THERE ARE NO OPERATING SAVINGS ASSOCIATED WITH*

FCRC 07-00381

Reliable Economic Dispatch of 800 MW Units

Results - Cash Flow Analysis

	31 2037	32 2038	33 2039	34 2040	35 2041	36 2042
Operating Savings						
Fuel Savings	0.00	0.00	0.00	0.00	0.00	0.00
Emission Cost Savings	0.00	0.00	0.00	0.00	0.00	0.00
Total Operating Savings	0.00	0.00	0.00	0.00	0.00	0.00
Operating Costs						
Operating Cost Initial Investment	0.00	0.00	0.00	0.00	0.00	0.00
Maintenance Cost (Vom Cycle)	0.00	0.00	0.00	0.00	0.00	0.00
On-Going O&M Costs (Nde Inspections)	0.00	0.00	0.00	0.00	0.00	0.00
Tax Depreciation - No Const.	0.00	0.00	0.00	0.00	0.00	0.00
Tax Depreciation - Const.	0.00	0.00	0.00	0.00	0.00	0.00
Property Taxes & Insurance	0.00	0.00	0.00	0.00	0.00	0.00
Total Project Costs	0.00	0.00	0.00	0.00	0.00	0.00
Net Project Savings (Cost)	0.00	0.00	0.00	0.00	0.00	0.00
Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00
After Tax Savings (Cost)	0.00	0.00	0.00	0.00	0.00	0.00
Add back Depreciation	0.00	0.00	0.00	0.00	0.00	0.00
After Tax Operating Cash Flows	0.00	0.00	0.00	0.00	0.00	0.00
Present Value @ 8.4%	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Present Value	873,605,078.52	873,605,078.52	873,605,078.52	873,605,078.52	873,605,078.52	873,605,078.52
CAPITAL INVESTMENTS:						
Capital Investment -No Const	0.00	0.00	0.00	0.00	0.00	0.00
Capital Investment - Construction	0.00	0.00	0.00	0.00	0.00	0.00
Investment in Land	0.00	0.00	0.00	0.00	0.00	0.00
Total Capital Investments	0.00	0.00	0.00	0.00	0.00	0.00
Present Value @ 8.4%	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Present Value	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34
Present Value Total Cash Flows	0.00	0.00	0.00	0.00	0.00	0.00
Cumulative Present Value	780,763,314.18	780,763,314.18	780,763,314.18	780,763,314.18	780,763,314.18	780,763,314.18
Net Present Value						
Discounted Pay-Back Period						
Internal Rate of Return of Cash Flows*						
After Tax Operating Cash Flows	0.00	0.00	0.00	0.00	0.00	0.00

** IRR IS IRRELEVANT IF THERE ARE NO OPERATING SAVINGS ASSOCIATED WITH*

ECRC 07-00382

Reliable Economic Dispatch of 800 MW Units

Results - Cash Flow Analysis

	37 2043	38 2044	39 2045	40 2046
Operating Savings				
Fuel Savings	0.00	0.00	0.00	0.00
Emission Cost Savings	0.00	0.00	0.00	0.00
Total Operating Savings	0.00	0.00	0.00	0.00
Operating Costs				
Operating Cost Initial Investment	0.00	0.00	0.00	0.00
Maintenance Cost (Vom Cycle)	0.00	0.00	0.00	0.00
On-Going O&M Costs (Nde Inspections)	0.00	0.00	0.00	0.00
Tax Depreciation - No Const.	0.00	0.00	0.00	0.00
Tax Depreciation - Const.	0.00	0.00	0.00	0.00
Property Taxes & Insurance	0.00	0.00	0.00	0.00
Total Project Costs	0.00	0.00	0.00	0.00
Net Project Savings (Cost)	0.00	0.00	0.00	0.00
Income Taxes	0.00	0.00	0.00	0.00
After Tax Savings (Cost)	0.00	0.00	0.00	0.00
Add back Depreciation	0.00	0.00	0.00	0.00
After Tax Operating Cash Flows	0.00	0.00	0.00	0.00
Present Value @ 8.4%	0.00	0.00	0.00	0.00
Cumulative Present Value	873,605,078.52	873,605,078.52	873,605,078.52	873,605,078.52
CAPITAL INVESTMENTS:				
Capital Investment -No Const	[illegible]	0.00	0.00	0.00
Capital Investment - Construction	0.00	0.00	0.00	0.00
Investment in Land	0.00	0.00	0.00	0.00
Total Capital Investments	0.00	0.00	0.00	0.00
Present Value @ 8.4%	0.00	0.00	0.00	0.00
Cumulative Present Value	92,841,764.34	92,841,764.34	92,841,764.34	92,841,764.34
Present Value Total Cash Flows	0.00	0.00	0.00	0.00
Cumulative Present Value	780,763,314.18	780,763,314.18	780,763,314.18	780,763,314.18
Net Present Value				
Discounted Pay-Back Period				
Internal Rate of Return of Cash Flows*				
After Tax Operating Cash Flows	0.00	0.00	0.00	0.00

** IRR IS IRRELEVANT IF THERE ARE NO OPERATING SAVINGS ASSOCIATED WITH*

ECRC 07-00383

Florida Power & Light's Responses to

Staff's 4th PODS No. 12

070007

Q.

Provide documents showing the calculations of the $12 million projected cost for the LLW Storage Project.

A.

The attached document, Bates numbered ECRC 07-00372, provides a cost estimate of $6 million related to LLW Storage Project activities at the St Lucie Plant. This estimate was doubled to obtain an estimate for both St. Lucie and Turkey Point plant sites, arriving at the total cost estimate of $12 million.

OCT 19

Florida Power and Light

Nuclear Project Budget Forecast (By Priority)

Facility	PSL	2007 Priority	380	2008 Priority		Project Start Dat	6/1/2008	Prepared by	Russ Merle	BDGT Item ID:	202
Unit	00	Corp Objectiv	Regulatory			In Service Date	12/1/2009	Approved by	Gordie Johnston		
Expense Type	Capital	Plant Health Committee		☐ Business Case	☐ Engineering Comple	☐ PRB Level	No PRB	Project Type	New		
BRC	064604	Description	Low Level "Class C" Waste Building								
BA/SA Number	00184PSLLLC	Capital ER		BUCS WO		CAR Nbr	None	Est. Typ.	Conceptual	BDGT Resp	NP-PSL

	Prior YR Acutals	2007 Frcst	2008 Frcst	2009 Frcst	2010 Frcst	2011 Frcst	2012 Frcst	Out Years
Engineering (400)	$0	$0	$400,000	$500,000	$0	$0	$0	$0
Equipment_Material (500)	$0	$0	$0	$1,000,000	$0	$0	$0	$0
Implementation (600)	$0	$0	$0	$2,500,000	$0	$0	$0	$0
Project Support (700)	$0	$0	$100,000	$600,000	$0	$0	$0	$0
Contingency (800)	$0	$0	$100,000	$800,000	$0	$0	$0	$0
Conceptual (999)		$0	$0	$0	$0	$0	$0	$0
Grand Total:	$0	$0	$600,000	$5,400,000	$0	$0	$0	$0

Cash Flow:

Year	CompCd	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YE Sum
2008	4000	0	0	0	5,000	5,000	10,000	10,000	15,000	15,000	5,000	400,000	0	$460,000
2008	7000	0	0	2,000	3,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	0	$40,000
2009	4000	0	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	0	$100,000
2009	5000	0	25,000	50,000	50,000	100,000	100,000	200,000	200,000	150,000	100,000	50,000	40,000	$1,065,000
2009	6000	25,000	50,000	100,000	200,000	300,000	400,000	400,000	400,000	400,000	300,000	300,000	311,479	$3,186,479
2009	7000	10,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	10,000	$220,000
2010	4000	0	20,000	0	0	0	0	10,000	0	0	0	0	0	$30,000
2010	5000	25,000	20,000	5,000	0	0	0	0	0	0	0	0	0	$50,000
2010	6000	200,000	174,760	174,760	125,000	24,451	0	0	0	0	0	0	0	$698,851
2010	7000	10,000	10,000	10,000	10,000	10,000	0	0	0	0	0	0	0	$50,000

ITD Actuals Total:	$0	Curr YR Frcst Total:	$600,000	5-Yr Request Total:	$6,000,000	ProjectTotal:	$6,000,000

Project Description:	The scope of this project includes the engineering and design of a storage facility with a five year capacity of spent resin and low level waste generated by PSL. The storage facility will house polyethlene containers filled with spent resins and filters placed inside engineered concrete shielded containers.
Project Benefits:	Based on current legislation the Barnwell, South Carolina facility will close to new shipments of low level waste in June of 2008. This facility is required for the on-site storage of low level waste.
Consequences if Project Not Completed:	If Barnwell closes PSL will have not have storage for low level rad waste
Basis Justification for Project Costs:	PSL's order of magnitude estimate is based on the PTN's Estimating and Scoping Efforts to date. PSL Project details are forthcoming.

ECRC 07-00372

070007-Hearing Exhibit 000245

Florida Power & Light

Panel Deposition Transcript of

Dubin/LaBauve of 10/25/07

and Late Filed Exh. (Nos. 1, 2, 3, 4)

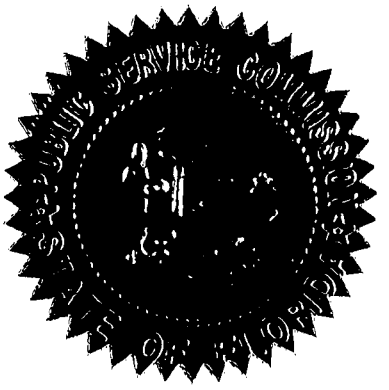
070007

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070007-EI

In the Matter of

ENVIRONMENTAL COST RECOVERY CLAUSE.
_____/



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TELEPHONIC DEPOSITION OF:	K. M. DUBIN R. R. LaBAUVE
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Room 382D Gerald L. Gunter Building 2540 Shumard Oak Boulevard Tallahassee, Florida
TIME:	Commenced at 10:00 a.m. Concluded at 11:19 a.m.
DATE:	Thursday, October 25, 2007
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732

070007-Hearing Exhibit 000247

APPEARANCES:

JOHN T. BUTLER, ESQUIRE, Florida Power & Light Company, 700 Universe Blvd., Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

JOHN T. McWHIRTER, ESQUIRE, McWhirter Reeves Law Firm, 117 S. Gadsden St., Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

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

070007-Hearing Exhibit 000248

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NAME:	PAGE NO.
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070007-Hearing Exhibit 000249

EXHIBITS

NUMBER:		ID.
1	(Late filed) FPL CAIR/CAMR Filing Update	11
2	(Late-filed) Reburn and Low NOx Study Costs	14
3	(Late-filed) Inspections work contractor for St. Lucie Cooling Water System Project	32
4	(Late-filed) January 2008 Expected Costs for St. Lucie Cooling Water Project	36
5	(Late-filed) Draft Biological Opinion and Assessment	39

070007-Hearing Exhibit 000250

S T I P U L A T I O N

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

070007-Hearing Exhibit 000251

PROCEEDINGS

MS. BROWN: Let's go on the record. This is the panel deposition of FP&L Witnesses Korel M. Dubin and Randall R. LaBauve in Docket Number 070007 EI, the environmental cost-recovery clause. Let's take appearances.

I am Martha Carter Brown on behalf of the Commission Staff.

MR. BUTLER: This is John Butler on behalf of Florida Power and Light Company.

COMMISSIONER McMURRIAN: John McWhirter, Jr., on behalf of Florida Industrial Power Users Group.

MS. BROWN: John, I didn't forget you that time.

MR. McWHIRTER: I appreciate it.

MS. BROWN: Would the notary please swear in the witnesses.

(Witnesses sworn.)

MR. BUTLER: All right. I think we're ready to go.

K.M. DUBIN

R.R. LaBAUVE

was called as a witness and, after being duly sworn by the court reporter, testified as follows:

DIRECT EXAMINATION

BY MS. BROWN:

Q Good morning, Ms. Dubin and Mr. LaBauve. Am I pronouncing your name right, Mr. LaBauve?

070007-Hearing Exhibit 000252

A Yes, you are.

Q Okay. Ms. Dubin, would you state your name and business address for the record?

A (By Witness Dubin) My name is Korel M. Dubin. 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 and Light Company as Manager of Cost-recovery Clauses in the Regulatory Affairs Department.

Q You have filed direct testimony and exhibits in this docket, correct?

A Yes.

Q All right. Mr. LaBauve, would you state your name and business address for the record?

A (By Witness LaBauve) Randall R. LaBauve, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q By whom are you employed and in what capacity?

A I'm employed by Florida Power and Light Company, and I am the Vice-president of Environmental Services.

Q And you have filed direct testimony and exhibits in this docket also, correct?

A Yes.

Q All right. Before we get to specific questions, I wanted to let you know that we have questions on three subjects

070007-Hearing Exhibit 000253

this morning. They are updates on FPL's CAIR/CAMR plan filed March 30th, 2007, with some questions about Scherer Unit 4, consideration of possible future CO2 capture and sequestration requirements, and, finally, questions regarding the St. Lucie cooling water system inspection and maintenance plan.

Since this is a panel deposition, whoever can respond best to the question, or if you both wish to respond, please feel free to do so. We believe we'll get more complete information that way. And for the court reporter's sake, though, please identify yourself at least at the beginning when you speak.

All right. Are we all set?

MR. BUTLER: Sounds fine.

MS. BROWN: All right.

BY MS. BROWN:

Q The CAIR/CAMR follow-up we'll do first.

Do you all have FPL's supplemental CAIR/CAMR filings with you, the filed March 30th?

MR. BUTLER: I don't know. We've got the discovery, we have the testimony, I'm not sure if we do. We can probably get that printed out pretty quickly if you would like for them to have that.

MS. BROWN: Well, it probably would be helpful to them, because we have some specific questions about paragraphs in the filing.

070007-Hearing Exhibit 000254

So do you want to take two minutes?

MR. BUTLER: Yes. Let's just take a couple of minutes. We'll print it out and then we will just continue.

MS. BROWN: Okay, thanks.

(Off the record.)

BY MS. BROWN:

Q Well, on Paragraph 1, at the bottom of Page 1 of that filing, FPL indicates that SER costs were estimated at that time to be 41.6 million. Has that estimation changed?

A (By Witness LaBauve) I think the estimates on the SER costs, and I'm working by memory here --

Q Okay.

A This is Randy LaBauve. Based on my memory, I seem to recall that the current estimate is around 45 million.

Q Okay. And can you explain the $4 million jump?

A Not at this time, no.

Q Okay. The estimated capital costs of the FGD unit on Scherer 4 was 358.4 million. You can see that at Paragraph 2 of the filing. Do you know if that estimate has changed, and if so, why?

A Right now -- (Pause.)

MR. BUTLER: Hold on just a second. We're trying to get the information for you.

MS. BROWN: All right, that's fine.

(Pause.)

070007-Hearing Exhibit 000255

MR. BUTLER: Martha?

MS. BROWN: Yes, John.

MR. BUTLER: The reason for the long pause here, I'll let Mr. LaBauve respond to you, it looks like the information we have most ready access to isn't broken up quite the same way that the figures that you are citing to are broken down. But I just wanted you to understand that's why it is taking a while to try to respond to your question. The problem is about, you know, some common costs that are wrapped into a category called common costs instead of allocated to elements it looks like.

MS. BROWN: Okay. You mean on Scherer?

MR. BUTLER: Yes.

Randy, go ahead.

A (By Witness LaBauve) The current estimate that we have at this time for all the work that is going to be done at Scherer Unit 4, and that would be FPL's cost, is 494 million. Now, when I look at some of the specific things that are associated with the scrubber, I can add up right now a total of 320 million of that being at least for the scrubber, and then there's other categories that have to do with, like, common facilities. And we have like a common facilities column that has 195 million, so there is obviously probably a portion of that that goes to the scrubber cost that was probably in the previous estimate in Paragraph 2 where we had quoted 358. So it's hard right now for me to tell how this number compares to

070007-Hearing Exhibit 000256

the 358.

MR. BUTLER: We could do a late-filed exhibit that shows what the current equivalent figure is, if you are interested.

MS. BROWN: Yes, I am interested. That is what I was just going to suggest. And while you are at it, why don't you do a late-filed exhibit for the previous question I asked about the 41.6 million that you indicate in your filing, and that would be to answer the question has that projection changed, and if so, why. Do you think you could do that?

MR. BUTLER: Yes, we can do that.

MS. BROWN: All right. How about if we do that as two questions in one late-filed exhibit titled "FPL CAIR/CAMR Filing Update." Is that all right?

MR. BUTLER: Okay. And so what it would end up being is updating the cost estimates that were reflected in the March 2007 supplemental filing for the SER costs and the Scherer FGD or scrubber costs to current figures and explaining the reason for any difference in the estimates.

MS. BROWN: Yes, that would be great.

MR. BUTLER: All right.

(Late-filed Exhibit 1 marked for identification.)

BY MS. BROWN:

Q All right. Paragraph 4 of your filing discusses NOx burners at Cape Canaveral, reburn and low NOx burners at Cape

070007-Hearing Exhibit 000257

Canaveral, Port Everglades, Turkey Point, and Putnam. Have you incurred any costs related to those projects? I know you talk about not continuing them, and we're trying to figure out whether you have incurred any costs related to them to this point?

A (By Witness LaBauve) I think the only costs that we would have incurred on any of those projects is the work that we may have done in evaluating what we need to do to comply with the CAIR requirements. We have not actually engineered any of the projects or spent any capital or O&M dollars associated with doing those projects.

Q Do you have an idea of what that number would be?

A Of the study costs?

Q Yes.

A No, not right now. I'm not associated with that particular portion of the project.

MR. BUTLER: Is that what you are asking is associated with that particular portion?

It sounds like there is sort of a general compliance review study, and it would have related to these and other projects. Are you looking for that overall compliance, you know, sort of study costs, or trying to break out a part that relates particularly to these projects?

MS. BROWN: You know, I'm not sure. I think overall compliance costs would be all right. And we're also interested

070007-Hearing Exhibit 000258

if you are recovering them anywhere or requesting recovery for them through a clause.

MR. BUTLER: Okay.

MS. BROWN: So do you want to make another late-filed exhibit?

MR. BUTLER: Yes. I think that probably makes sense.

MS. BROWN: And since you are going to do that, if you would, if you could break out the costs for the reburn and low NOx burners that would be helpful.

MR. BUTLER: If it's possible. Again, it sounds like -- what I understood is that this was a study of what the compliance options were.

MS. BROWN: Right.

MR. BUTLER: And if that's right, it is probably pretty hard to say how much you spent on looking at one option versus another. The point of the study is to explore the options. But if there is a way that it makes sense to break out, we will try to do it.

MS. BROWN: All right. That's fine, or an explanation of why it can't be done.

WITNESS LABAUVE: I will just tell you right now -- and we will do the late-filed exhibit, but my recollection on it was that when we did our previous filings we particularly wanted to get some study costs to evaluate the 800-megawatt project, and I think we went out and hired a firm to help us do

070007-Hearing Exhibit 000259

that. I think a lot of the costs, or any of the costs associated with evaluating the other reburn projects mostly was done by internal staff looking at those projects and evaluating what we needed to do. But we'll go back to see if any of the filing dollars that we put into the clause were associated with looking at the reburn project.

MS. BROWN: All right. That would be helpful, and we will call that Late-filed Exhibit 2, and we will title it "Reburn and Low NOx Burner Costs."

MR. BUTLER: I think it would be study costs.

MS. BROWN: Okay, that's fine.

(Late-filed Exhibit 2 marked for identification.)

BY MS. BROWN:

Q Do you have with you today the projected capital and O&M costs for each CAIR and CAMR compliance activity in either nominal or real terms?

A I have estimates of the total cost at Scherer, I have estimates of the total cost at St. Johns, and I think in the discovery responses we have estimates of the costs associated with the 800-megawatt project.

Q What are the total costs at Scherer?

A The current estimate of total capital costs at Scherer is 494 million. And that would be FPL's share.

Q Okay. And St. Johns?

A St. Johns, FPL's share of the total capital costs,

070007-Hearing Exhibit 000260

the estimate currently is $45.5 million.

Q Okay. And did I understand you that we can get the projected capital and O&M costs for the other projects from your discovery response?

A Yes.

Q Okay. Do you remember which one that is? Is it Number 36?

MR. BUTLER: I think it may be. Hold on just a second, we're looking it up.

A (By Witness LaBauve) The discovery response would be Request Number 11 to staff's third request for production of documents.

Q All right.

Let's turn to staff's fourth set of interrogatories, Number 38. Do you have that?

A Okay.

Q We were talking about this, I think, a little bit earlier. Our question has to do with FPL's share of the Unit 4 scrubber. I think you said that you are obligated to pay a share of that scrubber. Is that by contract with Georgia Power and Southern Company?

A Yes. We have an operating agreement amongst the co-owners of that unit.

Q Okay. When did FPL enter into that operating agreement?

070007-Hearing Exhibit 000261

A It was entered into when we purchased our share of Unit 4. I would have to do some research to find the exact year that that occurred. I seem to recall it was in the early '90s.

Q Okay. Well, that's good enough.

As a co-owner of Scherer 4, did FPL have any input into the decision to install the scrubber?

A Yes.

Q What was that -- can you describe that for me?

A There were a series of meetings that took place over the last couple of years where obviously we could see the adoption of the various laws that were coming into play, such as the Clean Air Mercury Rule, the Clean Air Interstate Rule, the Clean Air Visibility Rule. We were also aware of some of the nonattainment issues that were occurring in the Macon County area and the Atlanta area, and as a result of all of that we were cognizant that there was going to at least be some compliance obligations at Scherer 4.

Along the way, we have regular discussions with the co-owners and with Georgia Power, who manages that unit for us. And then as we started working our way through the process, they actually called special meetings. I would attend some of those meetings where we would specifically talk about the different requirements that were affecting the units and what the options may be. And as time went on, we got a better and

070007-Hearing Exhibit 000262

better understanding of what the requirements would be on Scherer 4, and what the state requirements in Georgia were going to impose upon the unit.

And as we walked through that, we continued to evaluate the options, and through the operating committee of Scherer 4, which we participate, eventually Georgia Power came to the co-owners with recommendations as to the compliance preferences for Scherer Unit 4, and eventually we worked our way to agreement on what that compliance plan would be.

Q Who from FPL sits on the operating committee?

A At the time that a lot of these discussions were ongoing, it was Al Alphonso (phonetic), who was our Vice-president of Fossil Generation in Florida Power and Light. I would just mention that recently a few months ago, Al did move to a different position within our company where he is now the Vice-President of our Distribution Area, and there is a new Vice-President of Fossil Generation, and that would be Keith Hardy (phonetic), and they would be the official reps to the operating committee. And along the way, because this was a particular environmental issue, and they wanted our advice and consultation, they did involve me in that process.

Q Are those meetings still going on?

A There is a regular operating committee meeting. I think it is once a quarter they have an operating committee meeting.

070007-Hearing Exhibit 000263

Q When FPL was providing its input into the decision to install a scrubber on Scherer 4, did FPL consider the cost impacts of possible future carbon capture legislation?

A At the time that we were evaluating the compliance options for Scherer 4, certainly there was the recognition that at some point in time there could be carbon-related legislation, either on a federal or state level, but it really wasn't very active at that point in time, particularly in Georgia.

As a couple of years have moved on, and particularly now and almost in the last few months we have seen a lot more activity, particularly in Florida on the carbon issue. But, still, not very much so in Georgia. So it really wasn't a major factor in terms of the compliance plan for Scherer 4 because the focus at that point in time was all of the other different provisions which we have to comply with, and we focused on those provisions with the recognition that at some point in time we may have to address the other issues, as well.

Q Are you continuing to evaluate that issue?

A Yes.

MR. BUTLER: That issue being?

MS. BROWN: Being impacts of possible future carbon capture legislation with respect to Scherer 4 or any of FPL's plants.

WITNESS LABAUVE: As we work our way through the

070007-Hearing Exhibit 000264

Florida process where they are currently working on proposed regulation to implement the Governor's executive orders on climate change we are in the early stages of basically doing some what-if scenarios of what may possibly occur. But at this point in time it is so early, it's very difficult to determine exactly what the impact may be to FPL or any of its particular units, but we are continuing to look at that on a regular basis.

BY MS. BROWN:

Q We want to explore this a little more with you regarding carbon capture and sequestration requirements and their related costs and what effect those requirements may have on your CAIR, CAMR, and CAVR plans. We understand that FPL faces actual existing regulations with respect to CAIR, CAMR, and CAVR requiring certain compliance by 2009, and we acknowledge that most of the questions we have about carbon require speculation on FPL's part and answers that cannot be supported by any solid facts and figures. Nevertheless, we want to discuss it with you because we think the Commissioners are concerned about it and we feel obligated to address the matter to some extent.

So the next questions we ask, we would ask that you answer as well as you can and with all the qualifications and caveats about the speculative nature of it that you feel you need to make. So I would like to proceed on that basis, with

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your agreement.

MR. BUTLER: That's fine. Given what you just said, I will note that, you know, I would object to the extent the answer calls for speculation, but direct Mr. LaBauve to respond to the extent he can.

MS. BROWN: Well, that would be great, and we want to make clear we understand that concern. You know, we're not going to hold anyone's feet to the fire on this, we just want to get a feel for what FPL is considering and evaluating in this area.

MR. BUTLER: Understood.

BY MS. BROWN:

Q Now, Interrogatory Number 39, FPL's response, this request asked FPL to provide a financial analysis comparing the retrofit of FPL's Scherer 4 as proposed by FPL with replacement generation based on a natural gas combined cycle unit under base high and load carbon capture sensitivities. As a point of clarification to FPL's response to this, in FPL's determination that the replacement suggested by staff could not be economically justified, did FPL consider an expected range of potential costs based on possible future carbon capture legislation?

MR. BUTLER: I would note, Martha, that this answer is really a follow-on to the answer to 38.

MS. BROWN: Right. And you may well have already

070007-Hearing Exhibit 000266

answered it, so let's move on to some more carbon capture questions.

BY MS. BROWN:

Q Is FPL a member of the Chicago Climate Exchange?

A No, we are not.

Q Does FPL participate in any carbon allowance market activity?

A FPL the utility does not.

Q FPL some other entity does?

A FPL Group, and particularly our FPL lead division, does participate in various state programs that involve the trading and management of renewable energy credits. They also are looking into the possibility of doing some voluntary carbon trading to the extent that we can participate in certain markets and market some of the renewable generation we have developed in FPL leads.

Q Okay. What particular markets are you participating in? Or you are considering doing it, is that right?

MR. BUTLER: You, in this instance, refers to FPLE?

MS. BROWN: Yes.

A FPLE is in 26 different states. We have a consideration amount of wind generation. We have some solar generation in California. Through many of those states, through the Midwest, Texas, different areas have RPS requirements and they have renewable energy credits in which we

070007-Hearing Exhibit 000267

actually do some trading and management on. I think the broader concept of getting involved in a voluntary carbon trading program would be much more widespread where they would essentially try to market to the general market and probably would be anybody who would want to participate there in the country, and potentially, I guess, even overseas that would want to so called offset their carbon footprint by buying credits that we create and hopefully have verified, I think they're trying to participate in that market.

Q All right. Does FPL believe that carbon regulation will be imposed on electric utilities in the U.S. on or before 2025 or so?

A You know, to the best of my understanding, we believe that, you know, carbon regulations are in the process of evolving both on a state, regional, and national level. There are a considerable number of bills in Congress. There are some states that are actively moving forward with putting provisions in place that effect different operations. And, yes, we do see the future including some carbon regulation.

The timing on that is difficult to judge. We have been saying for a number of years that, well, maybe it is three to five years away, and I still hear that it may three to five years away. But when you put a date such as 2025 out there, we would foresee that unless something remarkably changes that there will probably be some mandatory requirements

070007-Hearing Exhibit 000268

by that time.

Q All right. Do you have any idea, or has FPL considered what actions it would likely take to comply with environmental requirements similar to those included in Governor Crist's executive order?

MS. BROWN: John, do you all have that with you? That's about all we're going to ask about it. We're not going to ask too many specifics.

MR. BUTLER: I don't know that we have a copy of it here. I'm suspecting that Mr. LaBauve is familiar enough with it to be able to answer general questions, but if you get into specifics on it you may need to either specifically quote it or we can probably get a copy of it.

MS. BROWN: All right. We're really not asking for specifics.

BY MS. BROWN:

Q I guess the question is has FPL considered how it might comply with the requirements that Governor Crist has proposed?

A Yes. And I'm very familiar with the Governor's executive orders. We have been working on it daily since they came out in July. And, generally, I guess what I would describe to you, and you probably know it well by reading it, is that there are requirements that are really imposed upon the electric utility industry in the state of Florida to meet the

070007-Hearing Exhibit 000269

2000 levels of emissions that were occurring in 2000 by the year 2017, to meet 1990 level by the year 2025, and 80 percent below that by 2050. That is about as specific as the order gets at this point in time.

DEP is in the process of developing a rule of how they would actually implement these requirements. There is still a great deal of ambiguity as to how that rule could unfold in terms of its specifics. And I guess what I would tell you is that there are a variety of ways that it could actually be implemented in the state of Florida. One way could be that everybody has to meet a standard emission rate, and that if everybody met that rate, you know, basically you do the math of that rate times the number of megawatt hours that we all produced, then we would be able to meet the 2000 and 1990 levels.

If they do it in the form of requiring an emission rate, there is relatively minor impact on Florida Power and Light because our emission rates are so low. I think the majority of impacts would actually fall to those that have higher emission rates in other portions of the state.

If they move towards developing a cap and trade program, there's a whole lot of specifics that have to be worked through in how a cap and trade would be implemented in Florida, and how the so-called allocations of allowances would be given out to the different players. Under some scenarios,

070007-Hearing Exhibit 000270

if the allocations are done under what we call an output based formula, which is based upon how much electricity you produce in a base line, we think we would actually be in pretty good shape in terms of what our projected emissions would be versus the number of allowances we would get.

If the allocations were based upon an input basis, which is essentially awarding allowances based upon historical emissions, we would get fewer allowance and, therefore, our compliance obligation would be more difficult as we move forward.

There is also the potential scenario where the allocations aren't even given out for free, but rather they may be auctioned off by the states such that all the allowances that we might need in the future to be able to operate we would have to buy in an auction. And under that scenario you have to do some forecasting as to what you think the price may be for allowances in the market and then what your otherwise viable alternatives may be to either do efficiency projects, try to increase renewable generation, doing other things that might be less costly than buying allowances.

And under that scenario we generally favor an auction approach. We think if they are going to have a cap and trade that it would be the preferred approach to go with. It would result in added cost to us because we would have to buy every allowance that we might need, but our general position on this

070007-Hearing Exhibit 000271

rule is that the revenue that is collected from that should go to several different areas, one of which being investing in technologies that are going to be needed to comply with carbon requirements in the future, and the bulk of the money basically being recycled back to consumers, and so there is really a net neutral effect on our customers.

So, all of that being said, it may not give you an exact answer as to what the impact may be to us in terms of the Governor's executive orders. There can be a range anywhere from relatively minor to no impact all the way to possibly a more challenging impact for us to where particularly when you get to the 2025 or the 2050 numbers. We would have to basically find some more advanced technologies to be able to comply with the requirements.

Q Well, assuming that there would be no carbon allowance market, have you considered which of your generating units you might choose to shut down or derate first if environmental requirements impose that on you?

A No, we have not gone through a retirement analysis.

Q And you don't have any ideas on that at this point?

A Not at this point, no. And we are not anticipating -- I will tell you we are not anticipating that we really have the ability to retire units. Our load is growing every year. We need the generation sources that we have to meet that load. The ability to site new generation is becoming

070007-Hearing Exhibit 000272

more and more difficult in our ability to be able to get the permits and get them sited. And I know we all believe that the current generation that we have in place is going to be needed in the future. We are going to have to find a different way to be able to operate those units and either reduce the carbon emissions from them or otherwise obtain offsets or credits so that we can operate them.

Q With CAIR and CAMR controls installed on Scherer 4 at the current cost projections, does FPL expect that Scherer will be a more or less costly source of power compared to its projected system average cost of generation?

MR. BUTLER: Compared to FPL's system average cost?

MS. BROWN: Yes.

WITNESS LABAUVE:

A (By Witness LaBauve) I don't know that I have an evaluation of the net cost of energy from Scherer after the controls versus the rest of the FPL system.

MS. BROWN: All right. We're going to take a minute or two and probably come back with some wrap-up questions on carbon issues, and then we'll move on to St. Lucie water system. All right?

MR. BUTLER: All right.

(Off the record.)

MS. BROWN: All right. We are ready to move forward. John, one sort of follow-up question for the

070007-Hearing Exhibit 000273

questions we just asked. With respect to the late-fileds that you all are going to provide to us updating your March 30th filing, if there is anything else in that filing after you have reviewed it that you think the Commission needs to be updated on in order to determine whether that compliance is reasonable and prudent, would you include that in that late-filed?

MR. BUTLER: Okay. So what you are what asking is for us to look at the whole of the supplemental filing, and if any of the numbers or other information in there ought to be changed based on current information, to do so?

MS. BROWN: Yes, please.

MR. BUTLER: We can do that.

MS. BROWN: All right, great. Well, let's move on to the St. Lucie water system inspection and maintenance project.

BY MS. BROWN:

Q Mr. LaBauve, on your August 3rd direct testimony, Page 7, there is Form 42-4E, or KMD-2. Can you turn to that?

MR. BUTLER: Hold on a second, we're getting to it here.

MS. BROWN: Fine.

MR. BUTLER: I'm sorry, Page 7 of it?

MS. BROWN: Yes.

MR. BUTLER: You said the August 3 testimony, right?

MS. BROWN: Yes.

MR. BUTLER: Our Page 7 is talking about a different

070007-Hearing Exhibit 000274

program. It's talking about the Martin drinking water system program.

WITNESS DUBIN: Did you say KMD-2?

MS. BROWN: I did. And that's in your testimony, Ms. Dubin. Sorry.

MR. BUTLER: Okay. So it's Page 7 of KMD-2?

MS. BROWN: Right, Ms. Dubin's KMD-2.

MR. BUTLER: Now, are you talking to Mr. LaBauve or Ms. Dubin? It's actually her exhibit.

MS. BROWN: Yes. Either one. This is a panel depo. I apologize for the goof.

Are we there?

MR. BUTLER: We are.

BY MS. BROWN:

Q Line 33 indicates that FPL estimates $8,088,753 will be spent in 2007 to perform the St. Lucie cooling water system inspection and maintenance. Is that correct, Ms. Dubin?

A (By Witness Dubin) Yes, that is correct.

Q Okay. Now, Exhibit 1 of Mr. LaBauve's affidavit to your January 5 petition for approval of the project, do you have that?

MR. BUTLER: Hold on. This is for the cooling water program petition.

MS. BROWN: Right.

MR. BUTLER: The attachment to his affidavit in

070007-Hearing Exhibit 000275

support of the cooling water project. Do you have that?

MS. BROWN: It's Exhibit 1 to the petition.

MR. BUTLER: Okay. We have his testimony, we have the discovery, I don't think we have the petition, so we're going to have to take a short break to get it.

MS. BROWN: That will be fine. Do you want me to give you the question I've got on it?

MR. BUTLER: We can try that. If he knows it off the top of his head, fine; if not, we can take a short break and get a copy of the affidavit.

BY MS. BROWN:

Q All right. Well, it appears that on Page 3, Item 12, FPL estimated that the cost of the project would be between 3 million and 6 million, and we just want to confirm that. And then of course ask about the increase.

A (By Witness LaBauve) I think I can answer it. I can at least give you our current estimated cost. We did an outage early this year, and this was when we actually sent in a robotic device to check the intake pipes, and the inspection costs were about $2 million. And then based upon what we found there, we planned a project out to actually clean the pipe, which is being done currently under the outage, and the current number that I have for the actual work to clean the pipe is 5.8 million. So together that's 7.8 million.

MS. BROWN: Right. It's getting close. Thank you.

070007-Hearing Exhibit 000276

BY MS. BROWN:

Q How did you procure the required services for the project? And I'm incorporating all aspects of that. That would be the inspection and then the means to redress whatever problems were found as a result of the inspection.

A They were both bid.

Q They were both bid. Okay. And what has FPL done to ensure that the cost of the inspections and the cost of maintenance is -- well, actually I think you just answered that, it's market-based. You bid them competitively, is that right?

A Yes.

Q And who is performing or has performed the inspections work?

A I have the name of the company that is actually doing the clean up, but I don't have the name of the company that did the inspection. I would have to get that for you.

MR. BUTLER: We can provide the name of the contractor for the inspection work as a late-filed exhibit, if you would like.

MS. BROWN: That would be good. I have lost track of what -- that would be Late-filed 3.

MR. BUTLER: That's what I have.

MS. BROWN: And it would be "Inspections Work Contractor for St. Lucie Cooling Water System Project."

070007-Hearing Exhibit 000277

MR. BUTLER: That's fine.

(Late-filed Exhibit 3 marked for identification.)

BY MS. BROWN:

Q And who is the entity performing the clean-up work?

A (By Witness LaBauve) That would be a company by the named of Underwater Construction Corp.

Q Okay. Now, going back to -- well, let me ask you this. Has all of the inspection work been completed?

A Yes, at this point in time.

Q Meaning that you will go back after the work is done and inspect again?

A Well, I guess what I mean by that is that during the last outage we did the inspection of the pipe and got an understanding of what needed to be done during this particular project. This work is being done now, and it will be completed during this outage, but part of the biological opinion that will be coming from the government will essentially require that over time we will have to continually inspect the pipe and make sure that we are not having subsequent growth that's effecting the turtles or fish that are going through there.

Q Okay. When you did the inspection, what did you find, what were the results?

A When we did the inspection, what we found was that -- and I'll bring you back in time. Back in the late 1980's, the velocity caps, which are really the point out of the ocean

070007-Hearing Exhibit 000278

where the water comes into these pipes, there are these velocity caps, those structures that are down on the bottom of the ocean.

In the late 1980's, two of the velocity caps had collapsed, and those velocity caps were repaired in the early '90s. When they were repaired there was no inspection done of the pipe at that point in time. So nobody has really gone into those pipes for about 25 years.

When we went in during the last outage last spring, what we found was that some of the debris from when those velocity caps had collapsed, some of that debris had gone into the pipe and was spread over the first 400 feet or so of the pipe section. In all three pipes there was also other associated debris that had come in through the velocity caps and had been deposited along the pipe area.

What we also found was that there was a substantial amount of barnacle growth that had developed at the opening of the pipes and pretty much over the first couple hundred of feet of the pipe structure all along the interior walls of the pipe, and along that concrete and debris that had been deposited along the bottom of the pipe.

Q Okay. Is it likely that FPL will be able to complete the required cleaning during the SL-2 outage in 2007?

A That is the plan. The divers are making progress. They are having to do it by hand, to dive in there, doing the

070007-Hearing Exhibit 000279

scraping. They are using jets and then they taking out the debris through the velocity cap. As of this week I was told that there was good progress being made. There was a bit of a problem in that there was some rough seas out there and they had to stop work at some point due to the rough seas because it wasn't safe. But the plan is to complete the work during this outage.

Q All right. Did this project cause FPL to extend the duration of the 2007 outage in April?

A Not to my understanding. I think the inspection was done during the outage time that was planned.

Q Okay. Do you have information on when small tooth sawfish takes occurred at the St. Lucie cooling system, and do you know how many takes occurred?

A Yes, I do. It was in 2005. I could probably look up the specific month. I think it was around May. It was May 2005 that we had one small-toothed sawfish come in. It is a very, very rare fish, but that was the one occasion that it came in.

MS. BROWN: John, I want to take just a couple of minutes to go through my remaining questions. I think we could probably scratch them out if you will give us like two minutes.

MR. BUTLER: That's fine.

(Off the record.)

MS. BROWN: All right, John. We're ready here. We

070007-Hearing Exhibit 000280

want to talk a little bit about the costs that you projected to be incurred in January 2008. It looks like it was about $442,000.

MR. BUTLER: Sorry, this is for which program?

MS. BROWN: This is for the St. Lucie cooling system clean up.

MR. BUTLER: I'm sorry, do you have a reference for that?

MS. BROWN: Yes. Form 42-5P, Page 22 of 41 of August 3rd Direct Testimony, Appendix 1. We just want to know what type of costs these are.

(Pause.)

MS. BROWN: Ms. Dubin, I think we gave you a wrong reference.

WITNESS DUBIN: Okay.

MR. BUTLER: This is the August 31 testimony, isn't it?

MS. BROWN: Yes. Sorry about that.

MR. BUTLER: I think we've got it now, but it took a little while.

BY MS. BROWN:

Q Well, I guess we just want to know what types of costs are involved that you are talking about here?

A (By Witness Dubin) The $442,000 O&M costs for '08, correct?

070007-Hearing Exhibit 000281

Q Uh-huh.

A And you're looking to see what kind of activities that included?

Q Yes.

A Martha, we want to make -- if John says it's okay, make it a late-filed.

Q That's fine.

MR. BUTLER: I think we are going to need to.

MS. BROWN: Okay. That will be Late-filed Exhibit 4, and I guess a breakout of costs expected to be incurred in January 2008 for the St. Lucie cooling water project.

MR. BUTLER: Okay.

(Late-filed Exhibit 4 marked for identification.)

BY MS. BROWN:

Q All right. Mr. LaBauve or Kory, I think, Mr. LaBauve, you can answer it. What is the status of the biological order to be issued by NOAA regarding this project?

A Where things stand right now is we have the draft biological opinion which had come out. The NRC has issued what they refer to as the biological assessment. They issued that in August to the National Marine Fisheries, it's a division of NOAA, and in there they set forth their terms and conditions, and that was where they were describing the necessity to inspect and clean the pipe.

What happens at this point in time is that NOAA, or

070007-Hearing Exhibit 000282

the National Marine Fisheries, which is a division of them, has the ability to ask questions about that biological assessment. And once they are completed with their questions, they have 135 days to actually issue the biological opinion. We think that time has actually started, because we think all of their questions were answered, and we're hopeful that we will get the biological opinion by early next year. The date that I heard was in January.

Q All right. Is there a copy of the draft opinion or the biological assessment in this case, the evidence in the case? I don't think so.

A I think that was all filed, but if it was not, we can certainly get it for you.

Q Well, my guess is it was filed. So, let's just leave it at that.

Now, just a couple more questions about this project. Are there other benefits that FPL expects that are related to the completion of this project besides compliance with the biological order, any other efficiency improvements or costs savings that are going to result from this?

A No.

MS. BROWN: All right. Just one sec for a follow-up, and we'll be right back.

(Off the record.)

MS. BROWN: All right. John, I think we are about

070007-Hearing Exhibit 000283

done. I did want to follow up on the biological assessment and the draft opinion. Can we have one more late-filed which will be 5, that says that you will provide a copy of it if you haven't already, and if you could provide us a reference, if you have, where you have.

MR. BUTLER: We will just provide it. I think as you were going through your notes, it looks to us like we probably provided what Mr. LaBauve was referring to in response to some OPC production requests. You would not have received a copy of that, so we will just make it Late-filed Exhibit 5.

MS. BROWN: Okay. That sounds good. And we will just call it "Draft Biological Opinion and Biological Assessment."

MR. BUTLER: Yes. I think, if I'm not mistaken, that there isn't a draft biological opinion. Is that right?

WITNESS LABAUVE: There is a letter.

MR. BUTLER: There is a letter about it.

MS. BROWN: Well, that will be fine. Whatever you have got, if we could have it that would be appreciated.

MR. BUTLER: Okay. We can do that.

MS. BROWN: My staff is telling me we have the draft letter, but we don't think we have the assessment.

MR. BUTLER: Okay. So what you want is the biological assessment?

MS. BROWN: Yes.

070007-Hearing Exhibit 000284

MR. BUTLER: Okay.

(Late-filed Exhibit 5 marked for identification.)

MS. BROWN: And that is all the questions I have. Mr. McWhirter, do you have any? I guess not.

John, do you have any follow up?

MR. BUTLER: Let me look at my notes just one moment before I say no. I don't think I do, but let me check.

(Pause.)

MR. BUTLER: Martha?

MS. BROWN: Yes, John.

MR. BUTLER: I have just a couple of very short follow-up questions. They are to Mr. LaBauve.

CROSS EXAMINATION

BY MR. BUTLER:

Q Mr. LaBauve, you mentioned the take of one small sawtoothed sawfish in the St. Lucie intake structures. Does the biological assessment or biological opinion refer to turtles as well as to small-toothed sawfish fish?

A Yes.

Q And has there been takings of turtles attributed to the conditions inside the intake structures?

A Yes. We started noticing in the early '90s after the velocity caps had collapsed that some of the turtles started coming through with scrapes and injuries on them. Our people that manage that program keep very detailed statistics on this

070007-Hearing Exhibit 000285

and they saw a very steep upward curve over time of the number of injured turtles that were coming through the pipes. So, simultaneous and in a parallel path to the small-toothed sawfish incident, there was also a discussion ongoing about the number of turtles that were actually being impacted by the pipe. And then we got to the point in '06 where we actually exceeded our take limit. And it was decided at that point in time by the NRC and NOAA to combine the consultation of the two of them together in one biological opinion.

Q And the reference you just made to exceeding the take limit, that was exceeding the take limit for what type of animal?

A I think it was Green and Loggerheads.

Q Turtles?

A Turtles.

MR. BUTLER: Thank you. That's all the questions that I have.

MS. BROWN: All right. Thank you, John. I guess we can conclude this deposition.

Do you all want to read?

MR. BUTLER: Yes, we would like to read and sign, please.

MS. BROWN: Okay.

(The deposition concluded at 11:19 a.m.)

070007-Hearing Exhibit 000286

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IN RE: DOCKET NO. 070007-EI
NAME: K.M. DUBIN and R.R. LaBAUVE
DATE:

PAGE	LINE	CHANGE

CERTIFICATE OF OATH

STATE OF Florida

COUNTY OF Palm Beach

I, the undersigned authority, certify that Randall LaBauve personally appeared before me at Florida Power & Light (Deposition) Juno Beach and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Juno Beach, County of Palm Beach, State of Florida, this 25th day of October, 2007.

BEVERLY A. MILE
Comm# DD0453634
Expires 7/24/2009
Bonded thru (800)432-4254
Florida Notary Assn., Inc

Beverly A. Mile
Notary Public
State of Florida

Personally known ✓ ____ OR produced identification ____.

Type of identification produced NA.

CERTIFICATE OF OATH

STATE OF Florida

COUNTY OF Palm Beach

I, the undersigned authority, certify that Kory DuBin personally appeared before me at Florida Power & Light (Deposition) Juno Beach and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Juno Beach, County of Palm Beach, State of Florida, this 25th day of October, 2007.

BEVERLY A. MILE
Commit DD0453654
Expires 7/24/2009
Bonded thru (800)432-4254
Florida Notary Assn., Inc

Beverly A. Mile
Notary Public
State of Florida

Personally known ✓ OR produced identification _____.

Type of identification produced _____.

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

I, JANE FAUROT, Official FPSC Commission Reporter, do hereby certify that I was authorized to and did stenographically report the foregoing deposition at the time and place herein stated.

I FURTHER CERTIFY that this transcript, consisting of 40 pages, constitutes a true record of the testimony given by the witness.

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 29th day of October, 2007.

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

070007-Hearing Exhibit 000290

The following estimates from FPL's March 30, 2007 CAIR /CAMR Filing have changed, for the reasons discussed below. The other information in that Filing remains unchanged.

CAIR Compliance

- Installation of Selective Catalytic Reduction Systems (SCR) and Ammonia Injection Systems on St. Johns River Power Park (SJRPP) Units 1 and 2:

    - The current estimate is $45.5 million. FPL's previous estimate was $41.6 million. *The revision to the SJRPP environmental upgrade estimates at SJRPP is associated with completion of detailed engineering estimates and execution of the material and erection bidding process. All material and service contracts are being competitively bid; however, as contracts are awarded, the contracted costs may vary from the preliminary and definitive engineering estimates originally developed for the project.*

- Installation of Wet Flue Gas Desulfurization (FGD) Scrubber and SCR with Ammonia Injection Systems on Scherer Unit 4:

    - The current estimate is $426.3 million. FPL's previous estimate was $358.4 million. *FPL's previous estimate did not include the scrubber stack and some common facility cost. FPL is now getting a more defined scope and bids from vendors are coming in.*

- CAPITAL EXPENSES - CAIR:

    - Current Capital Cost estimate:
      Estimates now include Scherer, SJRPP, Martin and Manatee.

800 MW Cycling Unit	$103.8 million
Scherer & SJRPP	$471.9 million
Total	$575.7 million

    - Previous Total Capital Cost estimate: $400 million.

- REASONS FOR DIFFERENCE: *The previous estimate of $400 million did not include any costs for the 800MW Unit Cycling Project at Martin and Manatee. In addition, as discussed above, scrubber stack costs and some common facility costs at Scherer were not in FPL's previous estimate but are now included.*

- Actual Capital expenditures to date (as of 10/07): $18.1 million. *This has increased from the previous total of $9.5 million because of additional capital expenditures in the period between March and October.*

- O&M EXPENSES – CAIR:

  - Current annual O&M Cost estimate:
    - 2008 $2.0 million
    - 2009 $6.0 million
    - 2010-2012 $14.0 million

  - Previous annual O&M Cost estimate:
    - 2008-2011 $1.2 million
    - 2012+ $4.3 million

  - REASONS FOR DIFFERENCE: *The previous estimate did not include O&M costs for the 800 MW Unit Cycling Project at Martin and Manatee.*

CAMR Compliance

- CAPITAL EXPENSES - CAMR:

  - Current Capital Cost estimate:
    2007 $10.1 million
    Total $92.9 million

  - Previous Capital Cost estimate:
    2007 $26.1 million
    Total $100.1 million

  - REASONS FOR DIFFERENCE: *The previous estimate of $100.1 million has been reduced to $92.9 million as FPL has gotten more information from detailed engineering and from the execution of the material and erection bidding process.*

- Actual Capital expenditures to date (as of 10/07): $2.3 million. *The previous total should have been approximately $700,000 instead of $3.6 million. The total has increased from that figure because of additional capital expenditures in the period between March and October.*

LFE-2

Please reference FPL's response to Staff's Fourth Set of Interrogatories, No. 42. Reburn and Low NOx burner technologies were evaluated initially as part of the Black & Veatch study for FPL's CAIR compliance plan. Subsequent production cost modeling of FPL's system included changes to the base assumptions which reflected updates to the FPL generation expansion plan. These updates included the replacement of the proposed coal plant and use of gas fired generation in its place, the uprates of the existing Nuclear Units, and the addition of two new nuclear units within the FPL system. Model results identified the 800 MW Unit Cycling Project as providing both substantial reductions in NOx emissions and substantial fuel savings. The addition of new gas fired combined cycle units, new nuclear capacity, and the 800 MW project reduced FPL's need for further emission reductions through installation of controls to comply with the CAIR requirements based on current emission projections and allowance allocations. With the implementation of the 800 MW Unit Cycling Project , FPL does not currently anticipate the need to install additional controls on the units it operates to comply with CAIR and therefore does not presently intend to pursue the use of Reburn and Low NOx burner technology as previously projected. Consistent with the FPL's original projections of expenditures for the CAIR project, FPL has included the costs for the Black & Veatch study for ECRC cost recovery. Those costs total $296,000. FPL has not sought recovery of costs associated with its subsequent updated modeling work, because that work was done using existing internal resources.

Because the purpose of the Black & Veatch study was to evaluate multiple alternatives for CAIR compliance, it is neither possible nor appropriate to isolate expenditures for studying one particular alternative (such as the use of Reburn and Low NOx burner technology) from the expenditures for studying other alternatives. FPL is not seeking ECRC recovery for any costs that are specifically attributable to the use of Reburn and Low NOx burner technologies, whether for analysis, design or implementation.

LFE – 3

The contractor retained by FPL to conduct the inspection work on the St. Lucie cooling water system is Aquatic Sciences Inc. (ASI).

Docket No. 070007-EI
Florida Power & Light Company
Late Filed Exhibit 4, Page 1 of 2
Breakout of Costs Expected to be Incurred in January 2008 for the St. Lucie Cooling Water System Inspection and Maintenance Project

LFE-4

The original 2008 forecast for the St. Lucie Cooling Water System Inspection and Maintenance Project was $442,000. This forecast has been updated and reduced to $300,000. The estimated reduction is due largely to the consolidation of work scope/ tasks under one vendor contract and the reallocation of 2007 and 2008 forecasted budgeted dollars.

The forecasted $300,000 in 2008 is for project completion. The dollars for Project controls and project management will be utilized for project closeout reports, contract and invoice closeout and finalization, and audit document preparation. In 2008, engineering will participate in the engineering package final reviews and closeout. Implementation and rental dollars are required to restore work area to as found condition and store equipment. Dollars are also need to be retained in 2008 for payment liability to be incurred upon the receipt of the final report, to include all logs, photographs, and video from the vendor at the completion of the project.

Progress Energy's Responses to

Staff's 1st ROGS Nos. 1 - 25 (w/ Attachment 4)

070001

REDACTED

ECR

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	Docket No. 070007-EI
	Dated: October 15, 2007

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-25)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.340, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's First Set of Interrogatories (Nos. 1-25):

RESPONSES

1. **What, if any, affiliate relationships exist between PEF and the various entities contracting with PEF for CAIR and CAMR compliance services?**

   Response:
   There are no affiliate relationships between PEF and the various entities contracting with PEF for CAIR and CAMR compliance services.

2. **What, if any, vendor relationships for unregulated vendor services exist between PEF and the various entities contracting with PEF for CAIR and CAMR compliance services?**

   Response:
   There are no vendor relationships for unregulated vendor services between PEF and the various entities contracting with PEF for CAIR and CAMR compliance services.

3. **For each plan, please provide the components of costs and the cost amounts for each element of the plans shown in appearing in SSW-3 of Witness Waters direct testimony of June 1, 2007. Show annual detail.**

   Response:
   See Attachment No.3, which is being provided separately along with a Request for Confidential Classification.

4. **For each plan, please provide the components of costs and cost amounts aggregated to match the CPVRR data appearing in SSW-4 of Witness Waters direct testimony of June 1, 2007, to the extent it is different from the response to the preceding interrogatory. Show annual detail.**

DOCUMENT NUMBER-DATE
09425 OCT 15 07
FPSC-COMMISSION CLERK

Response:
See Attachments No. 4, which shows the values used in SSW-4. The values in SSW-4 are in 2007 dollars while the Net Present Values shown in the documents provided in Interrogatory 3 and the summary documents provided in Attachment No. 4 are presented in 2006 dollars. Attachment No. 4 shows the discount rate used to transform the 2006 dollar values into 2007 dollars.

5. **Please identify the data points reflected in Figures 1, 2, 3, 5, 6, 7, 8, and 11 of the document titled "Progress Energy Florida Integrated Clean Air Compliance Plan" filed June 1, 2007.**

Response:
See Attachment No. 5, a portion of which containing confidential information is being provided separately with a Request for Confidential Classification.

6. **Describe whether PEF considered potential carbon capture/sequestration requirements in its development of the cost requirements associated with Plans A through F, or in any compliance cost sensitivities it may have conducted.**

Response:
For the reasons discussed in response to Interrogatory No. 7 below, PEF did not consider potential carbon capture/sequestration requirements in the development of the alternative environmental compliance plans A through F, or in any cost sensitivities.

7. **If potential carbon capture and sequestration requirements were not considered in PEF's compliance plan or any sensitivities, why did PEF choose not to include such potential cost impacts in its compliance plan?**

Response:
When PEF committed to placing environmental controls on Crystal River Units 4 & 5 to meet the CAIR and CAMR regulatory requirements, climate change issues were only beginning to be discussed, and no cost estimates of carbon capture technologies were available, nor were "carbon tax" costs even defined. As such, PEF did not perform any such analyses at the time it had to make decisions to make regulatory commitments, execute contracts, and purchase equipment in order to meet all applicable regulatory requirements. At present, there has been increased discussions regarding potential carbon regulation at the federal and state levels; however, to date, no legislation or regulatory requirements enacted.

8. **Provide PEF's actual CO2 emissions (tons) for 1990 and 2000 and the expected emissions of CO2 in each year from 2017 through 2035 for each CAIR/CAMR Compliance Plans A through F.**

Generation Cost Analysis (real $/kwh)									
Unit Type	PEF Unit _____			Replacement Gas Unit(s)			Difference		
Fuel Price Forecast	Low	Base	High	Low	Base	High	Low	Base	High
Without Carbon Capture Requirements									
With Requirements of Governor's Executive Order 07-127									
With PEF's Expected Carbon Capture Requirements									

Response:

As discussed in response to Interrogatories No. 7 and 9, no carbon capture/sequestration requirements or technologies exist at the present time. The Florida Department of Environmental Protection (FDEP) is still in the early stages of developing a plan for implementing the Governor's Executive Order and numerous key issues, including the basis approach (i.e., cap-and-trade v. carbon tax or fee) remain unresolved. As such, PEF has not performed an analysis of the potential impacts of carbon capture on the Crystal River Units 4 and 5 scrubber project costs. PEF has, however, performed an analysis to determine the economic impact of replacing these coal-fired units with natural gas generation without consideration of carbon regulation. This analysis replaced the capacity of Crystal River Units 4 and 5 with combined cycle and combustion turbine capacity in a cost-optimal manner, as determined by the Strategist program. PEF's planned nuclear additions were left in place in the analysis. A comparison of total CPVRR costs of the case with CR 4 and 5 left in-service versus a case with the two units removed in 2017 shows a net increase in CPVRR of approximately $6 billion resulting from the shutdown of the units over the study period of approximately 40 years. Much of this increase in CPVRR to customers is the result of higher system fuel prices which follow from the replacement of coal energy with natural gas based energy. The cost to add environmental equipment to CR 4 and 5 is not included in this figure, i.e. the CPVRR cost would have to be subtracted from this total to obtain a net cost.

This analysis also did not, however, evaluate the impact of replacing Crystal River Unit 4 and 5 with natural gas capacity on PEF's overall fuel diversity and security. Shutdown of existing coal units and replacing the capacity with natural gas fired units would increase PEF's reliance on natural gas supplies and increase customer exposure to potential natural gas price volatility. Finally, although we believe that natural gas pipeline capacity in the state will increase to meet PEF's 2013 and 2014 demand, it is unlikely that gas transportation capacity could be installed in the state to replace the approximately 900MWs of coal capacity with natural gas by 2009.

Response:
PEF's actual CO2 emissions for 1990 were 20,394,767 tons and in 2000 they were 24,080,628 tons. For the reasons detailed in question 7 above, CO2 emissions were not calculated during the compliance plan analysis, so they are not available for Plans A-F.

9. **Does PEF believe it will be required to capture various forms of carbon emitted from its power plants during the period 2010 through 2035? Why/why not?**

Response:
As discussed in response to Interrogatory No. 7, no carbon capture/sequestration requirements exist at the present time and potential CO2 regulation is in the early stages of development and consideration. Moreover, no carbon capture/sequestration technology exists today and the feasibility and potential costs of these technologies remain uncertain. As a result, it would be impossible to determine whether carbon capture would be a feasible or cost-effective means of complying with any yet-to-be-determined CO2 regulatory regime.

10. **To the extent that PEF believes it will be required to capture carbon emitted from its power plants, provide PEF's view of a reasonable band of CO2 emissions allowance costs ($/ton CO2) for 2010 through 2035 based on the CO2 market which may result from such requirements. Explain how the band was developed.**

Response:
As indicated in the response to Question No. 9, PEF cannot determine whether it will be required to utilize carbon capture technology. Moreover, this question appears to assume a cap-and-trade system will be adopted when that may or may not be the case. For this analysis, PEF has made no assumptions about a reasonable band of CO2 emissions allowance costs based on a CO2 market that may result from carbon capture requirements.

11. **Provide an all-in generation cost analysis ($/kwh) of Crystal River Units 4 and 5 for CAIR and CAMR compliance activities included in Plan D, compared to replacement of the associated MW output with output from new natural gas combined cycle unit(s). Assume the earliest time that natural gas plants could be permitted, constructed, and operational, and use the expected remaining life of the replaced unit in your calculations. Assume base, high, and low fuel price sensitivities and carbon capture/sequestration requirements including: 1. no carbon capture requirements; 2. PEF's expected carbon capture requirements; and 3. Governor Crist's Executive Order 07-127 requirements. Provide all assumptions and calculations. Identify source(s) and date(s) of the fuel price forecasts, and provide fuel price forecasts. Complete the following "Generation Cost Analysis" matrix for each planned retrofitted unit.**

PEF will continue to re-evaluate its Integrated Clean Air Compliance Plan as any new regulations are developed, including any developed under the Governor's Executive Order or other state, regional or national initiatives. At this time, however, PEF must comply with the requirements of CAIR/CAMR/CAVR which, unlike potential CO2 requirements, are certain and require compliance as early as 2009. The analyses presented in PEF's 2006 Integrated Compliance Plan demonstrate that PEF's "Plan D" is the most cost-effective alternative for meeting those requirements. In addition, because Plan D focuses on Crystal River Units 4 and 5, which are the largest and most efficient coal units on PEF's system, additional actions may be pursued related to other PEF units as new regulations develop

12. Explain how PEF determined the expected number of allowances (equivalent allowances for SO2) shown in Figures 1-3 for each type of emission.

Response:
The expected number of allowances for each pollutant were determined as follows:

1. SO_2: SO_2 allowance allocations were first determined under Title IV of the Clean Air Act, also known as the Acid Rain Program. To calculate the allocations under CAIR, these allocations were divided by the appropriate CAIR factor, which is 2.0 for the years 2010 through 2014 and 2.86 for 2015 and beyond.
2. NOx: The NOx allowance allocations were obtained from the draft allocations calculated by the Florida Department of Environmental Protection (DEP).
3. Mercury: The mercury allowance allocations were obtained from the draft allocations calculated by the DEP.

13. Explain how PEF determined the expected emissions under the different plans as shown in Figures 1-3.

Response:
The projected emissions for the different plans were calculated using the following assumptions: projected annual amount of fuel burned (Btus) for the Crystal River and Anclote units, the sulfur content of the fuel (for SO2 emissions), the mercury content of the coal (for mercury emissions), the emission rate without controls (for NOx emissions), and the emission reduction capability of equipment installed (if any). The projected emissions for the units being included in the CAIR Compliance Plan were added to the projected annual emissions of the other PEF units (calculated in the same manner), for which controls are not being added. The projected annual amount of fuel burned was determined from a Prosym production cost model analysis.

14. What are the types and brands of each of the technologies (scrubber, LNB/SOFA, and SCR, etc.) which may be included in the PEF compliance plan in detail?

Response:
The Company has chosen to implement the following technologies at Crystal River 4 and 5 as part of its Integrated Clean Air Compliance Plan:

- Combination of Low NOx Burners (LNB) and Selective Catalytic Reduction systems (SCR's) for the removal of nitrous oxide.
  - LNB Manufacturer: Babcock & Wilcox Company
  - SCR System Manufacturer: Babcock & Wilcox Company
  - SCR catalyst manufacturer: CERAM Environmental, Inc.

- Wet Limestone Forced Oxidation (LSFO) Flue Gas Desulphurization (FGD) – also known as a 'scrubber,' for the removal of sulfur dioxide (SO_2).
  - FGD System Manufacturer: Babcock & Wilcox Company
  - FGD Absorber Tower Supply/Erection: The Stebbins Engineering & Manufacturing Company

PEF is still evaluating the installation of LNB/SOFA technologies at Anclote Units 1 & 2. Additional assessments will be required to determine the optimal compliance plan for these units.

15. Why were those types and brands chosen over other options.

Response:
The basis for the selection of B&W to provide the FGD system and the SCR system is detailed in the testimony of Mr. Thomas Cornell beginning on Page 13, line 4 and ending on page 15, line 5. In addition, it should be noted that the selection of B&W as the vendor for the supply of the LNBs was based on least cost $/ton of NOx removed among 6 potential vendors, along with the fact that B&W is the original equipment manufacturer for the CR 4&5 boilers.

Mr. Thomas Cornell's testimony, beginning on page 16 at line 5 and ending on page 21, line 4, also discusses the selection of CERAM as the SCR catalyst provider, Stebbins to supply and erect the absorber tower, and Commonwealth Dynamics, Inc. to design, fabricate, and erect the chimney.

16. If PEF is unable to identify the types and brands of each of the technologies which will ultimately be used in its 2007 PEF Integrated Clean Air Compliance Plan, when will it know?

Response:
PEF has completed its assessment of the types and brands of the primary technologies necessary for compliance at the Crystal River 4 & 5 site. With regard to the selection of

technologies for Anclote Units 1 & 2LNB/SOFA projects, it was noted in PEF's Integrated Clean Air Compliance Plan filed June 1, 2007, that PEF is analyzing whether the LNB/SOFA projects will result in increases of particulate emissions that trigger BACT requirements. If BACT is required, additional particulate controls, such as precipitators, would likely need to be installed and, as a result, the project schedules would need to be revised. If it is determined that precipitators or other controls need to be installed, PEF will evaluate whether the cost of the additional controls increases the cost per ton of NOx removal above the expected cost of NOx allowances. Because PEF's analysis of this issue is ongoing selection of the technologies for Anclote Units 1 & 2 LNB/SOFA projects have not been finalized.

17. **Identify the expected retirement date of each unit impacted by CAIR and CAMR compliance, and explain how CAIR and CAMR compliance may affect the unit retirement dates.**

Response:
For planning purposes, no retirement dates have been assumed for any of the units and CAIR/CAMR compliance is not expected to impact useable lives of the units.

18. **Provide an estimate of the impact of CAIR/ CAMR compliance on the annual *levelized ECRC factors* (cents/kwh) through the forecast horizon utilized in the CPVRR analysis.**

Response:
Below is an estimate of the impact of CAIR/CAMR compliance on the annualized ECRC factors. The estimates included below are not for the same forecast horizon that was utilized in the CPVRR analysis. The forecast horizon utilized in the CPVRR analysis is the life cycle of the projects. The forecast horizon being illustrated below is the same forecast horizon that was assumed in the April 2007 Ten Year Site Plan; therefore we have only estimated price impacts through 2016. The ECRC price impacts illustrated below will be partially offset by fuel savings associated with increased fuel flexibility.

2007 - $0.00
2008 - $0.04
2009 - $3.87
2010 - $5.46
2011 - $5.25
2012 - $5.06
2013 - $4.82
2014 - $4.72
2015 - $4.93
2016 – $4.51

19. Describe the process that identified only four qualified bidders for the EPC, including how those to be reviewed were selected and eliminated from consideration.

Response:
The Crystal River project represents a significant scope of work in terms of size and complexity. There is a limited pool of suppliers with the technical capability, experience, and financial strength to handle a project of this magnitude. Based on Progress Energy's general knowledge of the industry, experience with similar projects at Progress Energy Carolinas (PEC), knowledge of the capability and expertise of potential vendors, and the expected scope of work for the Crystal River project, PEF identified 4 major vendors as qualified and potential EPC contractors. The process through which the EPC contract was established is discussed in detail in Mr. Cornell's testimony beginning at Page 8, line 9 and ending at page 11, line 24.

20. Was the Request for Proposal for the EPC advertised, and if so, where?

Response:
The Company did not advertise the Request for Proposal for the EPC contract because there was only a limited pool of suppliers due to the complexities of this type of construction project.

21. Does the PEF Integrated Clean Air Compliance Plan include all the same generation assumptions included in the "PEF Ten Year Site Plan – April 2007"? Explain.

Response:
The PEF Integrated Clean Air Compliance Plan does not include all the same generation assumptions that were included in the "PEF Ten Year Site Plan – April 2007". The assumptions in the April 2007 Ten Year Site Plan were developed before the assumptions used in the PEF Integrated Clean Air Compliance Plan were developed. The differences are related to the timing of the studies being used in both analyses.

22. Reconcile the construction cost of Plan D as shown on Page 25 of the 2007 PEF Integrated Clean Air Compliance Plan ($1,260 million) with the contract pricing amounts included in Witness Cornell's testimony. If these amounts cannot be reconciled because there are costs in Plan D not included in Witness Cornell's testimony, please identify those costs components and the associated dollars.

Response:
The $1,260 million included in Page 25 of the 2007 PEF Integrated Clean Air Compliance Plan includes conceptual estimates related to installation of an LNB/SOFA at each of the two Anclote Units (approximately $12 million each) and an activated carbon injection system on Crystal River Unit 2 (approximately $38 million). The

remaining $1,200 million relates to the projects at Crystal River Units 4 & 5 and is the relevant amount to reconcile to Mr. Cornell's testimony.

Mr. Cornell's testimony notes the following contract costs:

- EPCR: $[redacted] million (anticipated at filing of Mr. Cornell's testimony)
- B&W: $[redacted] million estimated at filing of Mr. Cornell's testimony
- Worley Parsons: authorizations totaling $[redacted] million at the time of Mr. Cornell's testimony
- Stebbins Absorber Towers: totaling $[redacted] million for both units
- CERAM SCR catalysts: $[redacted] million
- CDI Flue Gas Chimney: $[redacted] million

These contracts noted in Mr. Cornell's testimony total approximately $[redacted] million. The remaining amount of approximately $[redacted] million is composed of the following items:

- Other contracts necessary for the completion of the projects.
- Estimated owner's labor and associated labor indirect costs
- Estimated owner's costs for additional boiler stiffening work, similar to work deemed necessary at other units on the Company's systems that have been retro-fitted with scrubbers
- Miscellaneous owner's costs such as builder's risk insurance, site accommodations for owner's staff, scrap yard costs, etc.

23. Regarding the price increases referenced on Page 6 and 7 of Witness Cornell's direct testimony of June 1, 2007, please provide a breakout of dollar cost increases from 2006 to 2007 by contract, showing 2006 costs, 2007 costs, and difference.

Response:
The cost estimates filed with the 2006 PEF CAIR compliance filing were estimated based on minimal design elements specific to the Crystal River units. There were no contracts approved or even near completion at the time of the 2006 filing.

24. Regarding the price increases referenced on Page 6 and 7 of Witness Cornell's direct testimony of June 1, 2007, please provide a breakout of dollar cost increases from 2006 to 2007 by unit specific compliance activity (those activities of Plan D as shown on Page 21 of the 2007 PEF Integrated Clean Air Compliance Plan), showing 2006 costs, 2007 costs, and difference.

Response:
($ in millions)

Unit	2006 Filing Amount	2007 Filing Amount	Increase / (Decrease)
Crystal River Unit 4 FGD	$242.8	$401.0	$158.2
Crystal River Unit 5 FGD	241.2	440.3	199.1
Crystal River Unit 4 LNB/SCR	105.1	185.0	79.9
Crystal River Unit 5 LNB/SCR	104.4	171.2	66.8
Anclote Unit 1 LNB/SOFA	5.4	12.3	6.9
Anclote Unit 2 LNB/SOFA	5.6	12.5	6.9
Crystal River Unit 2 Activated Carbon Injection	31.3	38.0	6.7
Total	$735.8	$1,260.3	$524.5

25. What tests of reasonableness did PEF perform to assure itself that the 2007 price increases of CAIR and CAMR compliance activities as reflected in the 2007 PEF Integrated Clean Air Compliance Plan were market-based?

Response:
The estimates used in the 2006 Integrated Clean Air Compliance Plan were based on the limited engineering and contract work done at the time of that filing. The 2007 estimates are based on more advanced engineering status, the known values for contracts that had been executed by the time of that filing, and the estimates that had been obtained for the EPCR contract at that time. Please refer to the testimony of Mr. Thomas Cornell on pages 8-21 for a detailed discussion of the status of and basis for contracts. Also refer to the response to Question No. 22 and the documentation provided in response to Production of Documents Requests Nos. 4 and 8 for further explanations.

DATED this 5th day of October, 2007.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko, Esquire
Florida Bar No. 855898
Virginia C. Dailey, Esquire
Florida Bar No. 419168
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

AFFIDAVIT

STATE OF NORTH CAROLINA)
)
COUNTY OF WAKE)

Before me, the undersigned authority, personally appeared Thomas Cornell, who

(✓) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 1, 2, 14, 15, 16, 19, 20, 21, 23, 24 and 25 of The Florida Public Service Commission's First Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 070007-EI are true and correct to the best of his knowledge, information and belief.

Thomas Cornell

G.M - Project Dev. & Engr.
Title

P D EDMISTON
NOTARY PUBLIC
WAKE COUNTY, N.C.
My Commission Expires 12-1-2007

Notary Public
State of North Carolina

My commission Expires: 12-1-07

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared J. Michael Kennedy, who

(✓) is personally known to me, or

( ) produced ——— as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatories No. 8 and No. 12 of Staff's First Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 070007-EI are true and correct to the best of his knowledge, information and belief.

J. Michael Kennedy

Principal Environmental Specialist
Title

Notary Public
State of Florida

My commission Expires:

LORETTA MURRAY
MY COMMISSION # DD 627692
EXPIRES: February 13, 2011
Bonded Thru Notary Public Underwriters

AFFIDAVIT

STATE OF NORTH CAROLINA)
)
COUNTY OF WAKE)

Before me, the undersigned authority, personally appeared Samuel S. Waters, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 3-7, 9-11, 13, 17 and 21 of The Florida Public Service Commission's First Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 070007-EI are true and correct to the best of his knowledge, information and belief.

Samuel S. Waters

Director, System Planning & Regulatory Performance
Title

PATTY LYN BOWERS NOTARY *** PUBLIC FRANKLIN COUNTY, N.C.

Notary Public
State of North Carolina

My commission Expires: November 21, 2010

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared MARITZA N. IACONO, who

(✓) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory No. 18 of Staff's First Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 070007-EI are true and correct to the best of her knowledge, information and belief.

Maritza N. Iacono
Maritza N. Iacono
Supervisor, Regulatory Planning Projects

Suzanne H Miller
Notary Public
State of Florida

My commission Expires:

SUZANNE H. MILLER
MY COMMISSION # DD 411455
EXPIRES: March 27, 2009
Bonded Thru Notary Public Underwriters

Progress Energy's

Attachment 4

070001

discount rate 8.10%

2007 dollars

	Plan A	Plan B	Plan C	Plan D	Plan E	Plan F
SO2	2,065	1,678	1,570	1,236	859	1,900
NOx	761	649	607	496	306	712
Mercury	0	22	30	41	155	0
Fuel	-906	-714	-680	-547	-106	-813
Consumables	78	67	64	69	49	72
Allowances (net)	25	165	195	295	658	145
Production Costs	-804	-482	-422	-183	602	-596
Total	2,022	1,867	1,786	1,590	1,922	2,016

Revenue . quirement Summary

$ Thousands

	Nominal	NPV	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SO2																			
Crystal River 1 FGD	1,033,752	328,869	0	0	0	43	263	798	60,252	69,174	65,353	61,651	57,927	55,093	53,176	51,760	49,733	47,953	46,479
Crystal River 2 FGD	1,280,241	438,160	0	0	53	327	990	74,536	85,366	80,419	76,044	71,262	67,744	65,879	63,406	61,174	59,342	57,183	54,957
Crystal River 4 FGD	1,740,739	548,582	4	104	520	1,374	68,826	89,488	86,127	81,806	78,426	75,325	71,203	68,109	67,016	65,218	63,233	62 201	59 863
Crystal River 5 FGD	1,752,741	594,521	7	142	646	70,223	90,475	86,284	82,486	78,814	75,023	71,433	69,018	66,890	64,525	63,920	61,302	59,932	58,284
Total SO2 Costs	5,807,472	1,910,132	11	246	1,220	71,967	160,554	251,106	314,231	310,212	294,846	279,671	265,893	255,971	248,123	242,072	233,610	227,269	219,582
NOx																			
Anclote 1 LNB/SOFA	34,750	13,586	0	5	427	2,313	2,138	1,966	1,787	1,681	1,646	1,602	1,547	1,503	1,457	1,420	1,366	1,320	1,272
Anclote 2 LNB/SOFA	34,528	13,323	0	2	12	2,026	2,270	2,094	1,921	1,743	1,643	1,594	1,543	1,502	1,456	1,418	1,362	1,326	1,269
Crystal River 1 SCR	309,814	103,215	0	0	0	4	43	181	19,862	22,620	21,262	19,923	18,591	17,608	16,977	16,390	15,763	15,154	14,569
Crystal River 2 SCR	394,079	141,825	0	0	19	116	351	25,256	28,730	26,998	25,321	23,626	22,380	21,610	20,805	20,023	19,272	18,497	17,717
Crystal River 4 SCR	685,315	224,660	4	56	246	627	29,828	38,209	36,443	34,634	32,904	31,208	29,462	28,181	27,420	26,617	25,802	25,049	24,213
Crystal River 5 SCR	588,038	206,958	3	49	230	25,445	32,642	31,075	29,549	28,046	26,550	25,081	24,027	23,328	22,616	22,017	21,289	20,643	19,979
Total NOx Costs	2,046,524	703,568	7	111	934	30,530	67,273	98,780	118,292	115,723	109,326	103,033	97,549	93,733	90,732	87,885	84,855	81,989	79,019
Visibility																			
Total Visibility Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury																			
Total Mercury Costs																			
Production Cost Changes																			
Fuel	-3,563,285	-838,475	0	0	0	0	-50,412	-52,479	-97,107	-95,233	-100,322	-106,572	-107,270	-102,672	-102,602	-109,813	-101,912	-107,973	-105,739
Consumables	336,482	71,990	0	0	0	1,844	6,423	4,095	5,499	5,880	6,430	6,953	7,209	7,550	7,697	8,481	8,339	8 920	9 024
Allowances	364,311	23,106	0	0	0	60,703	14,946	-14,254	-34,306	-36,655	-33,595	-13,673	-18,576	-16,860	-8,810	-2,164	-159	2 877	7 335
Total Prod Cost Changes	-2,862,492	-743,378	0	0	0	62,547	-29,042	-62,638	-125,914	-126,008	-127,487	-113,292	-118,636	-111 983	-103,714	-103,497	-93,732	-96 176	-89 380
Total Rev Requirements	4,991,504	1,870,322	18	358	2,154	165,044	198,784	287,248	306,609	299,927	276,686	269,412	244,806	237 721	235,141	226,460	224 733	213 082	209 221

File CostAnalysisSummary_PlanA Sheet Sheet1

Revenue ,uirement !

$ Thousands

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
SO2																	
Crystal River 1 FGD	44,821	43,189	41,883	40,147	38,514	36,933	35,358	33,789	13,594	9,808	10,002	10,277	10,560	10,850	11,149	11,455	11,770
Crystal River 2 FGD	53,215	51,010	49,204	47,443	45,201	43,231	41,269	16,208	11,496	11,718	12,040	12,372	12,712	13,061	13,421	13,790	14,169
Crystal River 4 FGD	58,489	57,414	55,734	53,825	52,654	51,205	49,766	48,438	47,321	46,316	45,322	44,339	43,367	42,407	41,459	40,524	23,316
Crystal River 5 FGD	56,489	55,069	54,220	52,345	50,806	49,337	47,983	46,850	45,834	44,828	43,832	42,848	41,874	40,913	39,963	22,652	17,495
Total SO2 Costs	213,013	206,682	201,042	193,760	187,175	180,705	174,375	145,285	118,245	112,670	111,197	109,835	108,513	107,231	105,991	88,420	66,749
NOx																	
Anclote 1 LNB/SOFA	1,233	1,194	1,161	1,118	1,065	1,022	978	935	892	754	124	128	131	135	139	142	146
Anclote 2 LNB/SOFA	1,233	1,185	1,157	1,115	1,061	1,018	974	931	888	845	226	111	114	117	121	124	127
Crystal River 1 SCR	13,970	13,374	12,802	12,199	11,604	11,014	10,424	9,835	2,832	1,477	1,491	1,532	1,574	1,617	1,662	1,707	1,754
Crystal River 2 SCR	16,975	16,198	15,451	14,708	13,930	13,173	12,417	3,460	1,724	1,738	1,786	1,835	1,886	1,938	1,991	2,046	2,102
Crystal River 4 SCR	23,440	22,686	21,895	21,090	20,332	19,558	18,785	18,061	17,431	16,849	16,269	15,690	15,113	14,538	13,965	13,394	5,313
Crystal River 5 SCR	19,306	18,659	18,048	17,373	16,720	16,072	15,467	14,946	14,467	13,990	13,514	13,040	12,568	12,097	11,629	4,837	2,737
Total NOx Costs	76,157	73,296	70,515	67,603	64,713	61,856	59,046	48,168	38,234	35,653	33,410	32,336	31,386	30,443	29,506	22,251	12,180
Visibility																	
Total Visibility Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury																	
Total Mercury Costs																	
Production Cost Changes																	
Fuel	-107,650	-114,209	-120,515	-117,185	-121,462	-124,757	-128,142	-131,620	-135,193	-138,863	-142,633	-146,507	-150,486	-154,574	-158,774	-163,089	-167,521
Consumables	9,519	10,146	11,080	11,248	11,764	12,320	12,888	13,469	14,064	14,672	15,295	15,932	16,583	17,250	17,932	18,630	19,344
Allowances	9,962	12,048	16,750	17,540	18,751	20,194	21,761	23,464	25,314	27,324	29,510	31,885	34,469	37,277	40,332	43,654	47,268
Total Prod Cost Changes	-88,170	-92,014	-92,685	-88,397	-90,946	-92,243	-93,493	-94,687	-95,815	-96,866	-97,829	-98,690	-99,434	-100,047	-100,510	-100,805	-100,910
Total Rev Requirements	201,001	187,964	178,872	172,966	160,941	150,318	139,928	98,766	60,664	51,457	46,778	43,482	40,465	37,627	34,987	9,866	-21,981

070007-Hearing Exhibit 000315

Revenue ,uirement Summary

$ Thousands

	Nominal	NPV	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SO2																			
Crystal River Coal Yard	98,047	29,656	0	0	0	0	0	0	13	666	7,593	7,286	6,989	6,701	6,422	6,151	5,887	5,627	5,368
Crystal River 2 FGD	1,373,278	379,978	0	0	0	0	0	59	362	1,097	74,959	95,264	89,830	84,835	79,244	75,285	73,128	70,680	68,183
Crystal River 4 FGD	1,740,739	548,582	4	104	520	1,374	68,826	89,488	86,127	81,806	78,426	75,325	71,203	68,109	67,016	65,218	63,233	62,201	59,863
Crystal River 5 FGD	1,752,741	594,521	7	142	646	70,223	90,475	86,284	82,486	78,814	75,023	71,433	69,018	66,890	64,525	63,920	61,302	59,932	58,284
Total SOz Costs	4,964,805	1,552,738	11	246	1,166	71,597	159,301	175,831	168,989	162,382	236,002	249,308	237,040	226,535	217,207	210,574	203,550	198,440	191,698
NOx																			
Anclote 1 LNB/SOFA	34,750	13,586	0	5	427	2,313	2,138	1,966	1,787	1,681	1,646	1,602	1,547	1,503	1,457	1,420	1,366	1,320	1,272
Anclote 2 LNB/SOFA	34,528	13,323	0	2	12	2,026	2,270	2,094	1,921	1,743	1,643	1,594	1,543	1,502	1,456	1,418	1,362	1,326	1,269
Crystal River 2 SCR	394,079	141,825	0	0	19	116	351	25,256	28,730	26,998	25,321	23,626	22,380	21,610	20,805	20,023	19,272	18,497	17,717
Crystal River 4 SCR	685,315	224,660	4	56	246	627	29,828	38,209	36,443	34,634	32,904	31,208	29,462	28,181	27,420	26,617	25,802	25,049	24,213
Crystal River 5 SCR	588,038	206,958	3	49	230	25,445	32,642	31,075	29,549	28,046	26,550	25,081	24,027	23,328	22,616	22,017	21,289	20,643	19,979
Total NOx Costs	1,736,710	600,353	7	111	934	30,526	67,230	98,600	98,430	93,103	88,064	83,110	78,958	76,125	73,755	71,495	69,092	66,835	64,450
Visibility																			
Total Visibility Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury																			
Crystal River 1 PAC	144,257	20,310	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15
Total Mercury Costs	144,257	20,310	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15
Production Cost Changes																			
Fuel	-2,818,919	-660,896	0	0	0	0	-50,412	-52,479	-58,163	-54,959	-80,531	-85,853	-85,974	-81,683	-82,485	-87,773	-81,891	-88,451	-84,431
Consumables	281,208	61,569	0	0	0	1,844	6,423	4,460	5,112	5,090	5,355	5,739	5,924	6,200	6,356	6,951	6,891	7,471	7,418
Allowances	740,571	153,049	0	0	0	60,703	14,946	-1,119	-925	-1	-6,203	11,891	4,466	2,891	6,141	10,880	11,605	14,251	19,277
Total Prod Cost Changes	-1,797,141	-446,278	0	0	0	62,547	-29,042	-49,138	-53,976	-49,870	-81,379	-68,224	-75,584	-72,593	-69,988	-69,941	-63,395	-66,729	-57,736
Total Rev Requirements	5,048,631	1,727,123	18	358	2,101	164,671	197,488	225,292	213,442	205,614	242,688	264,194	240,415	230,067	220,974	212,128	209,247	198,546	198,427

3/26/2007

File CostAnalysisSummary_PlanB, Sheet Sheet1

Revenue Requirements
$ Thousands

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
SO2																	
Crystal River Coal Yard	5,109	4,850	4,591	4,332	4,073	3,814	3,555	3,296	3,036	2,669	22	0	0	0	0	0	0
Crystal River 2 FGD	66,174	63,702	61,629	59,600	57,090	54,853	52,624	50,402	48,189	45,984	20,478	12,473	12,712	13,061	13,421	13,790	14,169
Crystal River 4 FGD	58,489	57,414	55,734	53,825	52,654	51,205	49,766	48,438	47,321	46,316	45,322	44,339	43,367	42,407	41,459	40,524	23,316
Crystal River 5 FGD	56,489	55,069	54,220	52,345	50,806	49,337	47,983	46,850	45,834	44,828	43,832	42,848	41,874	40,913	39,963	22,652	17,495
Total SO2 Costs	186,261	181,035	176,174	170,101	164,623	159,208	153,927	148,986	144,381	139,798	109,653	99,660	97,953	96,381	94,842	76,965	54,979
NOx																	
Anclote 1 LNB/SOFA	1,233	1,194	1,161	1,118	1,065	1,022	978	935	892	754	124	128	131	135	139	142	146
Anclote 2 LNB/SOFA	1,233	1,185	1,157	1,115	1,061	1,018	974	931	888	845	226	111	114	117	121	124	127
Crystal River 2 SCR	16,975	16,198	15,451	14,708	13,930	13,173	12,417	3,460	1,724	1,738	1,786	1,835	1,886	1,938	1,991	2,046	2,102
Crystal River 4 SCR	23,440	22,686	21,895	21,090	20,332	19,558	18,785	18,061	17,431	16,849	16,269	15,690	15,113	14,538	13,965	13,394	5,313
Crystal River 5 SCR	19,306	18,659	18,048	17,373	16,720	16,072	15,467	14,946	14,467	13,990	13,514	13,040	12,568	12,097	11,629	4,837	2,737
Total NOx Costs	62,187	59,922	57,712	55,404	53,108	50,843	48,622	38,333	35,402	34,176	31,919	30,804	29,812	28,826	27,844	20,543	10,426
Visibility																	
Total Visibility Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury																	
Crystal River 1 PAC	75	11,074	10,865	10,321	9,855	9,429	9,139	8,984	8,834	8,689	8,547	8,407	8,269	8,134	8,002	7,873	7,746
Total Mercury Costs	75	11,074	10,865	10,321	9,855	9,429	9,139	8,984	8,834	8,689	8,547	8,407	8,269	8,134	8,002	7,873	7,746
Production Cost Changes																	
Fuel	-85,959	-92,000	-95,772	-92,797	-96,624	-99,189	-101,822	-104,527	-107,305	-110,157	-113,086	-116,094	-119,182	-122,354	-125,611	-128,956	-132,391
Consumables	7,855	8,408	9,108	9,260	9,705	10,166	10,638	11,120	11,614	12,119	12,635	13,163	13,704	14,257	14,823	15,403	15,995
Allowances	21,925	20,136	25,422	25,804	26,845	28,203	29,682	31,292	33,046	34,956	37,035	39,299	41,763	44,445	47,364	50,542	54,000
Total Prod Cost Changes	-56,179	-63,456	-61,242	-57,733	-60,073	-60,819	-61,503	-62,115	-62,645	-63,082	-63,416	-63,631	-63,715	-63,652	-63,424	-63,012	-62,396
Total Rev Requirements	192,344	188,575	183,510	178,093	167,513	158,661	150,185	134,188	125,973	119,580	86,704	75,240	72,320	69,689	67,265	42,369	10,754

Revenue Requirement Summary

$ Thousands

	Nominal	NPV	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SO2																			
Crystal River 1 FGD	1,092,689	280,771	0	0	0	0	0	0	24	195	700	59,802	76,200	71,865	67,469	63,583	60,203	58,195	56,521
Crystal River Coal Yard	100,744	28,189	0	0	0	0	0	0	0	14	684	7,802	7,486	7,181	6,885	6,598	6,320	6,049	5,782
Crystal River 4 FGD	1,740,739	548,582	4	104	520	1,374	68,826	89,488	86,127	81,806	78,426	75,325	71,203	68,109	67,016	65,218	63,233	62,201	59,863
Crystal River 5 FGD	1,752,741	594,521	7	142	646	70,223	90,475	86,284	82,486	78,814	75,023	71,433	69,018	66,890	64,525	63,920	61,302	59,932	58,284
Total SO2 Costs	4,686,912	1,452,064	11	246	1,166	71,597	159,301	175,772	168,637	160,828	154,833	214,362	223,907	214,045	205,895	199,320	191,058	186,377	180,450
NOx																			
Anclote 1 LNB/SOFA	34,750	13,586	0	5	427	2,313	2,138	1,966	1,787	1,681	1,646	1,602	1,547	1,503	1,457	1,420	1,366	1,320	1,272
Anclote 2 LNB/SOFA	34,528	13,323	0	2	12	2,026	2,270	2,094	1,921	1,743	1,643	1,594	1,543	1,502	1,456	1,418	1,362	1,326	1,269
Crystal River 1 SCR	311,674	103,206	0	0	0	4	43	181	18,022	22,844	21,477	20,129	18,788	17,799	17,162	16,570	15,936	15,322	14,732
Crystal River 4 SCR	685,315	224,660	4	56	246	627	29,828	38,209	36,443	34,634	32,904	31,208	29,462	28,181	27,420	26,617	25,802	25,049	24,213
Crystal River 5 SCR	588,038	206,958	3	49	230	25,445	32,642	31,075	29,549	28,046	26,550	25,081	24,027	23,328	22,616	22,017	21,289	20,643	19,979
Total NOx Costs	1,654,304	561,734	7	111	915	30,414	66,922	73,524	87,722	88,948	84,220	79,613	75,367	72,313	70,111	68,041	65,757	63,660	61,464
Visibility																			
Total Visibility Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury																			
Crystal River 2 PAC	180,856	28,151	0	0	0	0	0	0	0	0	0	0	0	0	0	0	17	85	12,466
Total Mercury Costs	180,856	28,151	0	0	0	0	0	0	0	0	0	0	0	0	0	0	17	85	12,466
Production Cost Changes																			
Fuel	-2,687,935	-629,276	0	0	0	0	-50,412	-52,479	-58,163	-54,959	-56,790	-83,081	-84,075	-77,445	-79,182	-87,039	-77,479	-83,725	-81,817
Consumables	270,170	58,762	0	0	0	1,844	6,423	3,209	4,464	4,956	5,258	5,605	5,809	5,927	6,136	6,900	6,567	7,179	7,221
Allowances	809,358	180,416	0	0	0	60,703	14,946	9,633	4,316	1,039	7,697	19,142	6,520	6,879	8,595	11,315	14,232	17,024	16,789
Total Prod Cost Changes	-1,608,408	-390,098	0	0	0	62,547	-29,042	-39,637	-49,383	-48,965	-43,835	-58,333	-71,746	-64,638	-64,451	-68,823	-56,620	-59,582	-57,807
Total Rev Requirements	4,913,665	1,651,851	18	358	2,082	164,559	197,180	209,659	206,975	200,812	195,218	235,641	227,529	221,720	211,556	198,538	200,211	190,539	196,572

Revenue quirement S

$ Thousands

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
SO2																	
Crystal River 1 FGD	54,679	52,866	51,378	49,460	47,645	45,882	44,125	42,375	40,631	38,895	37,165	16,966	10,641	10,850	11,149	11,455	11,770
Crystal River Coal Yard	5,516	5,249	4,983	4,717	4,451	4,185	3,919	3,652	3,386	3,120	2,743	22	0	0	0	0	0
Crystal River 4 FGD	58,489	57,414	55,734	53,825	52,654	51,205	49,766	48,438	47,321	46,316	45,322	44,339	43,367	42,407	41,459	40,524	23,316
Crystal River 5 FGD	56,489	55,069	54,220	52,345	50,806	49,337	47,983	46,850	45,834	44,828	43,832	42,848	41,874	40,913	39,963	22,652	17,495
Total SO2 Costs	175,173	170,598	166,316	160,347	155,556	150,608	145,792	141,315	137,172	133,158	129,062	104,175	95,883	94,170	92,570	74,631	52,580
NOx																	
Anclote 1 LNB/SOFA	1,233	1,194	1,161	1,118	1,065	1,022	978	935	892	754	124	128	131	135	139	142	146
Anclote 2 LNB/SOFA	1,233	1,185	1,157	1,115	1,061	1,018	974	931	888	845	226	111	114	117	121	124	127
Crystal River 1 SCR	14,127	13,526	12,949	12,340	11,740	11,144	10,548	9,954	3,525	1,477	1,491	1,532	1,574	1,617	1,662	1,707	1,754
Crystal River 4 SCR	23,440	22,686	21,895	21,090	20,332	19,558	18,785	18,061	17,431	16,849	16,269	15,690	15,113	14,538	13,965	13,394	5,313
Crystal River 5 SCR	19,306	18,659	18,048	17,373	16,720	16,072	15,467	14,946	14,467	13,990	13,514	13,040	12,568	12,097	11,629	4,837	2,737
Total NOx Costs	59,340	57,250	55,210	53,036	50,918	48,813	46,754	44,827	37,203	33,914	31,624	30,501	29,500	28,505	27,515	20,205	10,078
Visibility																	
Total Visibility Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury																	
Crystal River 2 PAC	12,183	11,539	11,193	10,883	10,362	10,190	10,025	9,864	9,707	9,552	9,400	9,252	9,106	8,964	8,824	8,688	8,556
Total Mercury Costs	12,183	11,539	11,193	10,883	10,362	10,190	10,025	9,864	9,707	9,552	9,400	9,252	9,106	8,964	8,824	8,688	8,556
Production Cost Changes																	
Fuel	-81,280	-88,308	-92,718	-87,349	-92,406	-94,847	-97,353	-99,926	-102,569	-105,282	-108,068	-110,929	-113,866	-116,883	-119,980	-123,160	-125,426
Consumables	7,496	8,119	8,865	8,816	9,356	9,801	10,256	10,721	11,198	11,685	12,183	12,693	13,215	13,749	14,296	14,855	15,427
Allowances	19,917	21,481	26,492	27,650	28,220	29,563	31,027	32,622	34,359	36,252	38,313	40,558	43,001	45,662	48,558	51,711	55,143
Total Prod Cost Changes	-53,868	-58,708	-57,361	-50,883	-54,830	-55,483	-56,070	-56,583	-57,012	-57,345	-57,572	-57,678	-57,650	-57,471	-57,126	-56,594	-55,856
Total Rev Requirements	192,828	180,679	175,358	173,383	162,005	154,129	146,500	139,423	127,070	119,280	112,515	86,250	76,840	74,167	71,784	46,930	15,359

Revenue Requirement Summary

$ Thousands

SO2	Nominal	NPV	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Crystal River 4 FGD	1,740,739	548,582	4	104	520	1,374	68,826	89,488	86,127	81,806	78,426	75,325	71,203	68,109	67,016	65,218	63,233	62,201	59,863
Crystal River 5 FGD	1,752,741	594,521	7	142	646	70,223	90,475	86,284	82,486	78,814	75,023	71,433	69,018	66,890	64,525	63,920	61,302	59,932	58,294
Total SO2 Costs	3,493,479	1,143,104	11	246	1,166	71,597	159,301	175,772	168,613	160,619	153,449	146,758	140,221	134,999	131,541	129,138	124,535	122,133	118,146
NOx																			
Anclote 1 LNB/SOFA	34,750	13,586	0	5	427	2,313	2,138	1,966	1,787	1,681	1,646	1,602	1,547	1,503	1,457	1,420	1,366	1,320	1,272
Anclote 2 LNB/SOFA	34,528	13,323	0	2	12	2,026	2,270	2,094	1,921	1,743	1,643	1,594	1,543	1,502	1,456	1,418	1,362	1,326	1,269
Crystal River 4 SCR	685,315	224,660	4	56	246	627	29,828	38,209	36,443	34,634	32,904	31,208	29,462	28,181	27,420	26,617	25,802	25,049	24,213
Crystal River 5 SCR	588,038	206,958	3	49	230	25,445	32,642	31,075	29,549	28,046	26,550	25,081	24,027	23,328	22,616	22,017	21,289	20,643	19,979
Total NOx Costs	1,342,630	458,527	7	111	915	30,410	66,878	73,343	69,700	66,104	62,743	59,484	56,579	54,514	52,950	51,472	49,820	48,338	46,732
Visibility																			
Total Visibility Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury																			
Crystal River 2 PAC	180,971	37,863	0	0	0	0	0	0	0	0	0	14	71	11,145	10,435	9,876	9,615	9,412	9,553
Total Mercury Costs	180,971	37,863	0	0	0	0	0	0	0	0	0	14	71	11,145	10,435	9,876	9,615	9,412	9,553
Production Cost Changes																			
Fuel	-2,042,578	-505,705	0	0	0	0	-50,412	-52,479	-58,163	-54,959	-56,790	-62,362	-62,779	-56,456	-59,065	-64,998	-57,398	-64,213	-60,509
Consumables	300,591	63,587	0	0	0	1,844	6,423	3,209	3,552	3,629	3,944	4,362	4,524	8,932	9,044	5,371	9,084	9,529	9,504
Allowances	1,219,273	273,141	0	0	0	60,703	14,946	9,633	11,632	11,353	17,967	40,876	29,562	23,490	20,467	21,179	22,352	24,589	28,731
Total Prod Cost Changes	-522,714	-168,977	0	0	0	62,547	-29,042	-39,637	-42,979	-39,977	-34,879	-17,124	-28,694	-24,034	-29,554	-38,448	-25,962	-29,804	-22,274
Total Rev Requirements	4,494,367	1,470,517	18	358	2,082	164,555	197,137	209,478	195,334	186,747	181,314	189,131	168,178	176,625	165,371	152,038	158,008	149,779	151,287

Revenue , ,uirement S

$ Thousands

SO2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Crystal River 4 FGD	58,489	57,414	55,734	53,825	52,654	51,205	49,766	48,438	47,321	46,316	45,322	44,339	43 367	42,407	41,459	40,524	23,316
Crystal River 5 FGD	56,489	55,069	54,220	52,345	50,806	49,337	47,983	46,850	45,834	44,828	43,832	42,848	41,874	40,913	39,963	22,652	17,495
Total SO2 Costs	114,978	112,483	109,954	106,169	103,460	100,542	97,749	95,288	93,155	91,144	89,154	87,187	85,242	83,320	81,422	63,176	40,810
NOx																	
Anclote 1 LNB/SOFA	1,233	1,194	1,161	1,118	1,065	1,022	978	935	892	754	124	128	131	135	139	142	146
Anclote 2 LNB/SOFA	1,233	1,185	1,157	1,115	1,061	1,018	974	931	888	845	226	111	114	117	121	124	127
Crystal River 4 SCR	23,440	22,686	21,895	21,090	20,332	19,558	18,785	18,061	17,431	16,849	16,269	15,690	15 113	14,538	13,965	13,394	5,313
Crystal River 5 SCR	19,306	18,659	18,048	17,373	16,720	16,072	15,467	14,946	14,467	13,990	13,514	13,040	12,568	12,097	11,629	4,837	2,737
Total NOx Costs	45,212	43,724	42,261	40,696	39,178	37,670	36,206	34,873	33,678	32,438	30,133	28,969	27,927	26,888	25,853	18,498	8,324
Visibility																	
Total Visibility Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury																	
Crystal River 2 PAC	8,737	8,448	8,454	8,491	8,166	8,042	7,920	7,801	7,685	7,572	7,461	7,354	7,392	4,463	4,558	4,674	4,802
Total Mercury Costs	8,737	8,448	8,454	8,491	8,166	8,042	7,920	7,801	7,685	7,572	7,461	7,354	7,392	4,463	4,558	4,674	4,802
Production Cost Changes																	
Fuel	-59,589	-66,099	-67,975	-62,961	-67,568	-69,278	-71,033	-72,834	-74,681	-76,576	-78,521	-80,515	-82,562	-84,662	-86 817	-89,028	-91 295
Consumables	9,660	10,355	10,976	10,683	11,222	11,573	11,931	12,298	12,673	13,056	13,449	13,851	14,262	14,682	15 113	15,553	16 004
Allowances	31,880	33,650	39,971	40,949	41,735	43,472	45,369	47,440	49,699	52,163	54,849	57,777	60,968	64,445	68,232	72,357	76 850
Total Prod Cost Changes	-18,049	-22,095	-17,029	-11,329	-14,610	-14,233	-13,733	-13,096	-12,309	-11,357	-10,222	-8,888	-7,332	-5,535	-3,472	-1,117	1 558
Total Rev Requirements	150,878	142,561	143,641	144,027	136,194	132,020	128,142	124,866	122,209	119,796	116,526	114,622	113,227	109,136	108 361	85,229	55,494

Revenue Requirement Summary

$ Thousands

	Nominal	NPV	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SO2																			
Crystal River 1 FGD	977,862	353,560	0	10	124	506	50,015	63,938	60,116	56,912	53,450	51,021	49,486	47,844	46,116	44,865	42,990	41,359	40,035
Crystal River 2 FGD	1,249,487	441,238	0	13	145	596	21,921	85,397	80,846	75,973	71,657	68,152	65,893	64,045	61,593	59,361	57,511	55,346	53,115
Total SO2 Costs	2,227,348	794,798	0	23	269	1,102	71,936	149,335	140,962	132,884	125,106	119,173	115,379	111,889	107,709	104,226	100,501	96,705	93,150
NOx																			
Anclote 1 LNB/SOFA	34,750	13,586	0	5	427	2,313	2,138	1,966	1,787	1,681	1,646	1,602	1,547	1,503	1,457	1,420	1,366	1,320	1,272
Anclote 2 LNB/SOFA	34,528	13,323	0	2	12	2,026	2,270	2,094	1,921	1,743	1,643	1,594	1,543	1,502	1,456	1,418	1,362	1,326	1,269
Crystal River 1 SCR	294,090	113,057	0	4	44	180	16,895	21,401	20,099	18,851	17,592	16,677	16,094	15,511	14,925	14,375	13,779	13,202	12,647
Crystal River 2 SCR	385,811	143,160	0	5	52	211	7,613	28,842	27,152	25,450	23,801	22,562	21,767	21,011	20,215	19,436	18,696	17,914	17,136
Total NOx Costs	749,179	283,126	0	15	535	4,729	28,916	54,303	50,959	47,725	44,682	42,435	40,951	39,527	38,053	36,649	35,194	33,762	32,324
Visibility																			
Total Visibility Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury																			
Crystal River 4 PAC	290,293	57,660	0	0	0	0	0	0	0	0	0	21	105	15,372	15,314	14,709	13,969	13,942	12,945
Crystal River 5 PAC	294,667	85,622	0	0	15	78	12,567	12,045	11,764	11,545	11,209	10,995	10,874	10,292	9,626	10,269	9,411	9,479	9,338
Total Mercury Costs	584,961	143,282	0	0	15	78	12,567	12,045	11,764	11,545	11,209	11,016	10,979	25,664	24,941	24,979	23,380	23,421	22,283
Production Cost Changes																			
Fuel	-420,815	-97,631	0	0	0	0	7,318	-11,811	-12,268	-12,309	-12,987	-13,131	-13,423	-13,624	-12,863	-13,044	-13,478	-12,995	-13,394
Consumables	196,034	45,654	0	0	0	0	2,534	5,028	4,675	4,835	5,165	5,225	5,260	5,568	5,277	5,495	5,538	5,470	5,619
Allowances	2,134,866	609,064	0	0	0	82,986	92,612	63,811	67,547	59,669	67,089	97,311	79,024	58,129	50,722	48,401	44,952	53,257	50,807
Total Prod Cost Changes	1,910,085	557,087	0	0	0	82,986	102,464	57,028	59,954	52,195	59,266	89,405	70,861	50,073	43,136	40,852	37,012	42,733	43,032
Total Rev Requirements	5,471,573	1,778,294	0	37	819	88,895	215,883	272,711	263,639	244,349	240,264	262,029	238,169	227,152	213,839	206,705	196,088	195,621	190,788

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Revenue . quirement !
$ Thousands

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
SO2																	
Crystal River 1 FGD	38,526	37,044	35,887	34,301	32,818	31,385	14,552	9,289	9,474	9,734	10,002	10,277	10,560	10,850	11,149	11,455	11,770
Crystal River 2 FGD	51,348	49,137	47,305	45,514	43,265	41,273	32,988	10,534	10,705	10,972	11,247	11,528	11,816	12,111	12,414	12,724	13,043
Total SO2 Costs	89,875	86,181	83,193	79,815	76,082	72,659	47,541	19,823	20,179	20,707	21,249	21,805	22,376	22,962	23,563	24,180	24,813
NOx																	
Anclote 1 LNB/SOFA	1,233	1,194	1,161	1,118	1,065	1,022	978	935	892	754	124	128	131	135	139	142	146
Anclote 2 LNB/SOFA	1,233	1,185	1,157	1,115	1,061	1,018	974	931	888	845	226	111	114	117	121	124	127
Crystal River 1 SCR	12,079	11,513	10,970	10,397	9,832	9,271	3,242	1,317	1,325	1,359	1,392	1,427	1,463	1,500	1,537	1,575	1,615
Crystal River 2 SCR	16,394	15,619	14,873	14,130	13,353	12,596	9,604	1,581	1,588	1,628	1,668	1,710	1,753	1,797	1,842	1,888	1,935
Total NOx Costs	30,939	29,511	28,161	26,761	25,311	23,906	14,799	4,765	4,694	4,585	3,412	3,376	3,462	3,549	3,638	3,730	3,824
Visibility																	
Total Visibility Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury																	
Crystal River 4 PAC	12,669	12,746	12,502	12,084	12,213	12,132	12,056	11,984	11,916	11,852	11,793	11,739	11,690	11,645	11,619	11,626	11,651
Crystal River 5 PAC	9,085	9,108	9,555	9,233	9,160	9,135	9,114	9,108	9,126	9,158	9,194	9,236	9,282	9,332	9,388	9,552	7,395
Total Mercury Costs	21,753	21,854	22,056	21,317	21,373	21,267	21,170	21,091	21,041	21,010	20,987	20,974	20,971	20,978	21,008	21,177	19,046
Production Cost Changes																	
Fuel	-13,775	-13,934	-14,489	-15,016	-14,513	-14,830	-15,154	-15,486	-15,825	-16,172	-16,527	-16,890	-17,262	-17,642	-18,030	-18,428	-18,835
Consumables	5,958	5,971	6,528	6,778	6,745	6,950	7,160	7,374	7,594	7,818	8,048	8,283	8,524	8,770	9,022	9,279	9,543
Allowances	52,643	56,481	62,457	60,735	62,819	64,361	66,050	67,897	69,917	72,124	74,533	77,163	80,031	83,159	86,568	90,283	94,330
Total Prod Cost Changes	44,826	48,518	54,496	52,497	55,051	56,481	58,055	59,786	61,686	63,771	66,055	68,556	71,293	74,287	77,559	81,134	85,038
Total Rev Requirements	187,393	186,065	187,906	180,389	177,818	174,314	141,565	105,465	107,599	110,072	111,702	114,712	118,102	121,775	125,767	130,221	132,720

Revenue ...quirement Summary

$ Thousands

	Nominal	NPV	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SO2																			
Crystal River 1 FGD	1,084,406	278,491	0	0	0	0	0	0	12	147	601	59,311	75,603	71,293	66,921	63,060	59,701	57,712	56,057
Crystal River 2 FGD	1,398,818	335,847	0	0	0	0	0	0	0	16	179	732	77,728	99,274	93,313	87,625	82,382	78,308	75,658
Crystal River 4 FGD	1,740,739	548,582	4	104	520	1,374	68,826	89,488	86,127	81,806	78,426	75,325	71,203	68,109	67,016	65,218	63,233	62,201	59,863
Crystal River 5 FGD	1,752,741	594,521	7	142	646	70,223	90,475	86,284	82,486	78,814	75,023	71,433	69,018	66,890	64,525	63,920	61,362	59,932	58,284
Total SO2 Costs	5,976,703	1,757,442	11	246	1,166	71,597	159,301	175,772	168,625	160,782	154,229	206,801	293,553	305,566	291,775	279,823	266,618	258,152	249,861
NOx																			
Anclote 1 LNB/SOFA	34,750	13,586	0	5	427	2,313	2,138	1,966	1,787	1,681	1,646	1,602	1,547	1,503	1,457	1,420	1,366	1,320	1,272
Anclote 2 LNB/SOFA	34,528	13,323	0	2	12	2,026	2,270	2,094	1,921	1,743	1,643	1,594	1,543	1,502	1,456	1,418	1,362	1,326	1,269
Crystal River 1 SCR	340,775	90,552	0	0	0	0	0	0	4	52	218	20,088	25,430	23,900	22,377	20,903	19,782	19,079	18,410
Crystal River 2 SCR	444,310	109,804	0	0	0	0	0	0	0	6	63	260	26,411	33,464	31,420	29,412	27,450	25,995	25,065
Crystal River 4 SCR	685,315	224,660	4	56	246	627	29,828	38,209	36,443	34,634	32,904	31,208	29,462	28,181	27,420	26,617	25,802	25,049	24,213
Crystal River 5 SCR	588,038	206,958	3	49	230	25,445	32,642	31,075	29,549	28,046	26,550	25,081	24,027	23,328	22,616	22,017	21,289	20,643	19,979
Total NOx Costs	2,127,715	658,883	7	111	915	30,410	66,878	73,343	69,704	66,162	63,024	79,832	108,419	111,878	106,747	101,786	97,052	93,412	90,207
Visibility																			
Total Visibility Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury																			
Total Mercury Costs																			
Production Cost Changes																			
Fuel	-3,396,326	-752,388	0	0	0	0	-50,412	-52,479	-58,163	-54,959	-56,790	-62,362	-107,270	-102,672	-102,602	-109,813	-101,912	-107,973	-105,739
Consumables	326,882	66,945	0	0	0	1,844	6,423	3,209	3,552	3,629	3,944	5,273	6,859	7,550	7,697	8,481	8,339	8,920	9,024
Allowances	573,714	134,235	0	0	0	60,703	14,946	9,633	11,632	11,353	17,967	20,781	-13,021	-16,860	-8,810	-2,164	-159	2,677	7,335
Total Prod Cost Changes	-2,495,730	-551,208	0	0	0	62,547	-29,042	-39,637	-42,979	-39,977	-34,879	-36,308	-113,431	-111,983	-103,714	-103,497	-93,732	-96,376	-89,380
Total Rev Requirements	5,608,689	1,865,116	18	358	2,082	164,555	197,137	209,478	195,350	186,967	182,375	250,324	288,541	305,461	294,808	278,112	269,938	255,189	250,688

Revenue Requirements

$ Thousands

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
SO2																	
Crystal River 1 FGD	54,233	52,438	50,969	49,070	47,274	45,529	43,791	42,059	40,334	38,616	36,906	16,903	10,641	10,850	11,149	11,455	11,770
Crystal River 2 FGD	73,530	70,960	68,791	66,667	64,062	61,730	59,406	57,089	54,781	52,481	50,189	47,907	21,464	13,169	13,421	13,790	14,169
Crystal River 4 FGD	58,489	57,414	55,734	53,825	52,654	51,205	49,766	48,438	47,321	46,316	45,322	44,339	43,367	42,407	41,459	40,524	23,316
Crystal River 5 FGD	56,489	55,069	54,220	52,345	50,806	49,337	47,983	46,850	45,834	44,828	43,832	42,848	41,874	40,913	39,963	22,652	17,495
Total SO2 Costs	242,741	235,881	229,714	221,907	214,796	207,801	200,945	194,436	188,270	182,241	176,249	151,997	117,347	107,339	105,991	88,420	66,749
NOx																	
Anclote 1 LNB/SOFA	1,233	1,194	1,161	1,118	1,065	1,022	978	935	892	754	124	128	131	135	139	142	146
Anclote 2 LNB/SOFA	1,233	1,186	1,157	1,115	1,061	1,018	974	931	888	845	226	111	114	117	121	124	127
Crystal River 1 SCR	17,732	17,058	16,409	15,728	15,055	14,386	13,718	13,051	12,386	11,721	11,058	3,888	1,603	1,617	1,662	1,707	1,754
Crystal River 2 SCR	24,185	23,279	22,403	21,532	20,625	19,739	18,854	17,970	17,088	16,207	15,327	14,449	4,992	1,976	1,991	2,046	2,102
Crystal River 4 SCR	23,440	22,686	21,895	21,090	20,332	19,558	18,785	18,061	17,431	16,849	16,269	15,690	15,113	14,538	13,965	13,394	5,313
Crystal River 5 SCR	19,306	18,659	18,048	17,373	16,720	16,072	15,467	14,946	14,467	13,990	13,514	13,040	12,568	12,097	11,629	4,837	2,737
Total NOx Costs	87,130	84,061	81,073	77,955	74,858	71,795	68,778	65,895	63,152	60,366	56,518	47,305	34,522	30,481	29,506	22,251	12,180
Visibility																	
Total Visibility Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury																	
Total Mercury Costs																	
Production Cost Changes																	
Fuel	-107,650	-114,209	-120,515	-117,185	-121,462	-124,757	-128,142	-131,620	-135,193	-138,863	-142,633	-146,507	-150,486	-154,574	-158,774	-163,089	-167,521
Consumables	9,519	10,146	11,080	11,248	11,764	12,320	12,888	13,469	14,064	14,672	15,295	15,932	16,583	17,250	17,932	18,630	19,344
Allowances	9,962	12,048	16,750	17,540	18,751	20,194	21,761	23,464	25,314	27,324	29,510	31,885	34,469	37,277	40,332	43,654	47,268
Total Prod Cost Changes	-88,170	-92,014	-92,685	-88,397	-90,946	-92,243	-93,493	-94,687	-95,815	-96,866	-97,829	-98,690	-99,434	-100,047	-100,510	-100,805	-100,910
Total Rev Requirements	241,701	227,928	218,103	211,464	198,707	187,352	176,230	165,644	155,607	145,740	134,938	100,612	52,434	37,773	34,987	9,866	-21,981

Progress Energy Florida's Responses to

Staff's 2nd PODS No. 8

070007

ntage Changes in Producer Price Indexes (PPIs) for Construction Materials and Components, 2001-2007

		12 months through December--						to August 2007 since--			
		2001	2002	2003	2004	2005	2006	6/07	4/07	7/06	12/03
Table 1: Changes in Consumer, Producer & Construction Prices											
CUR0000SA0	Consumer price index (CPI-U) *(through July 2007)*	1.6	2.4	1.9	3.3	3.4	2.5	*0.0*	*0.8*	*2.4*	*13.0*
WPUSOP3000	Producer price index (PPI) for finished goods	-1.6	1.2	4.0	4.2	5.4	1.1	-1.4	-1.2	2.2	14.7
WPUSOP2200	PPI for materials and components for construction	0.0	0.8	3.0	10.1	6.1	4.3	-0.1	0.4	1.5	24.1
PCU236221236221	New warehouse construction	not available before 2005				7.5	8.1	0.3	1.4	5.4	n.a.
PCU236222236222	New school construction	not available; series began 12/05					17.3	-0.2	0.4	11.6	n.a.
PCU236222236223	New office construction	not available; series began June 2006						0.0	0.3	5.4	n.a.
Table 2: Changes in PPIs Weighted by Construction Types											
PCUBCON	Inputs to construction industries	-0.9	0.7	3.0	9.1	8.2	4.6	-0.8	-0.1	1.6	27.9
PCUBHWY	Highway and street construction	-3.6	1.0	2.6	10.8	14.1	6.2	-2.0	-1.3	1.5	42.6
PCUBHVY	Other heavy construction	-2.6	1.0	2.6	13.4	8.8	5.5	-1.1	-0.4	2.0	36.4
PCUBBLD	Nonresidential buildings	-0.5	0.7	2.4	9.3	7.4	4.0	-0.8	0.0	1.5	26.5
PCUBRSM	Multi-unit residential	-0.1	0.4	2.7	8.9	7.8	4.9	-0.6	0.1	1.9	26.8
PCUBRS1	*Single-unit residential*	-0.4	0.6	3.5	7.0	6.9	4.2	-0.3	0.4	1.7	22.1
Table 3: Changes in PPIs for Specific Construction Inputs											
WPU057303	#2 diesel fuel	-44.7	54.4	13.0	37.9	46.7	2.3	-3.3	3.9	-5.9	140.0
WPU05810112	Asphalt (at refinery)	not available		10.0	18.3	17.8	34.9	-5.7	1.2	-18.6	107.0
WPU13940113	*Asphalt paving mixtures and blocks*	not available			4.2	14.4	27.7	0.1	0.8	3.6	49.3
WPU136	Asphalt felts and coatings	4.6	-0.6	6.3	4.1	15.3	5.0	1.9	0.6	0.5	26.2
WPU1361	Prepared asphalt & tar roofing & siding products	5.0	-1.7	5.3	4.6	16.2	5.2	1.9	-0.1	2.3	27.4
WPU133	Concrete products	2.5	-0.3	1.5	7.6	10.1	8.1	0.0	0.2	3.5	31.5
WPU1331	Concrete block and brick	2.3	1.6	3.2	4.7	8.1	6.8	0.2	0.3	3.0	24.8
WPU1332	Concrete pipe	4.4	1.7	1.4	5.5	7.5	2.5	-0.1	0.5	1.8	18.4
WPU1333	Ready-mixed concrete	2.5	-1.1	2.1	8.7	11.3	10.1	0.0	0.5	3.4	36.5
WPU1334	Precast concrete products	0.7	0.3	2.5	6.0	6.0	4.7	0.3	-0.5	4.9	22.3
WPU1335	Prestressed concrete products	5.3	1.8	-0.2	8.2	14.3	4.9	0.4	-1.2	1.0	30.1
WPU1342	Brick and structural clay tile	5.3	1.9	0.7	3.0	9.4	6.0	0.2	0.2	1.1	19.8
WPU072106	Plastic construction products	-2.7	3.1	3.2	7.2	21.6	-0.7	0.2	0.7	-0.9	29.6
WPU137	Gypsum products	0.4	3.4	2.8	20.0	18.8	5.5	-2.6	-5.9	-21.8	27.5
WPU1392	Insulation materials	0.4	-1.5	2.0	8.6	2.6	2.1	-0.1	-1.1	-3.9	11.5
WPUSI004011	Lumber and plywood	-2.9	1.4	13.1	5.0	-1.1	-10.8	-1.5	1.5	-0.4	-2.8
WPU062101	*Architectural coatings*	2.9	0.6	3.9	5.3	9.2	6.3	0.1	-0.1	4.6	27.3
WPU1017	Steel mill products	-6.1	11.1	1.7	48.8	-3.8	11.6	-2.7	-5.3	-0.6	61.3
WPU101704	Hot-rolled bars, plates, & structural shapes	-4.3	2.1	11.3	53.8	-1.0	7.5	-2.0	-1.6	9.2	80.3
WPU101706	Steel pipe and tube	-3.7	9.1	3.3	66.0	1.2	5.5	0.4	0.3	-1.2	74.7
WPU102502	Copper and brass mill shapes	-9.5	-1.6	11.6	29.6	31.0	44.4	-1.2	2.8	2.6	168.3
WPU102501	Aluminum mill shapes	-2.9	-0.9	-0.5	9.9	5.0	12.7	-0.2	-1.6	3.4	32.0
WPU107405	Fabricated structural metal	-1.3	-2.4	0.1	24.7	2.8	3.6	-0.1	0.0	2.9	37.5
WPU10740501	Fabricated structural metal for buildings	-1.5	-3.3	-0.1	20.0	3.1	3.3	-0.1	0.2	2.9	32.6
WPU107408	Architectural and ornamental metalwork	-0.1	3.7	0.7	23.5	3.1	4.9	1.0	1.3	4.7	36.4
WPU107409	Fabricated iron & steel pipe, tube, & fittings	0.6	0.1	1.2	32.6	5.5	-2.8	0.7	-1.2	-6.3	36.3
WPU1076	Fabricated steel plate	0.6	-1.0	0.6	7.6	0.6	8.6	2.0	3.1	5.3	22.8
WPU1079	Prefabricated metal buildings	0.0	4.0	-0.7	35.5	2.0	5.5	0.8	1.3	2.7	47.7
WPU112	Construction machinery and equipment	-0.1	1.9	1.3	6.0	4.9	3.6	0.1	0.5	2.6	17.2
Table 4: Changes in PPIs for Basic Inputs Important to Construction											
WPU056	Crude petroleum (domestic production)	-42.4	60.6	14.3	30.5	49.6	-0.1	1.3	16.5	-0.3	137.9
WPU0553	Industrial natural gas	-36.7	12.2	20.3	20.1	31.5	-13.2	-5.2	-6.8	-1.3	26.2
WPU066	Plastic resins and materials	-9.8	9.2	6.4	28.6	10.8	-7.8	0.0	2.3	-1.7	38.1
WPU1321	Construction sand/gravel/crushed stone	3.3	2.5	2.4	4.3	7.7	9.3	0.6	1.1	7.8	31.4
WPU1322	Cement	1.0	1.3	-1.1	7.9	12.2	10.5	-0.3	-1.0	4.0	38.9
WPU1011	Iron ore	1.5	-1.3	1.6	6.7	15.5	7.5	0.0	0.5	-4.5	34.3
WPU1012	Iron and steel scrap	-5.6	27.8	64.9	50.8	-10.8	2.9	3.0	-1.1	17.5	67.7
WPU101212	Stainless and alloy steel scrap	no data from 1996 until September 2006						22.8	-44.7	n.a.	
WPU102102	Copper ores *(through 7/07; no data for 8/07)*	-19.6	3.6	37.4	65.1	39.3	53.1	*-1.0*	*12.9*	*-2.7*	*292.2*
WPU102301	Copper base scrap	-17.4	11.2	30.7	34.5	51.9	50.0	-3.8	-8.2	5.4	232.4

Updated 9/18/07 Source: Bureau of Labor Statistics (BLS): www.bls.gov/cpi for CPI, www.bls.gov/ppi for PPIs

Compiled by Ken Simonson (simonsonk@agc.org), Chief Economist, Associated General Contractors of America, www.agc.org

What's that scrubber going to cost?

The latest benchmarking study by the EUCG examines the technology and costs of 49 flue gas desulfurization systems currently under design or construction by 12 of the nation's largest utilities. Although the study's detailed results are proprietary to EUCG members that participated in it, *POWER* was given access to the top-level findings. To get details at the plant/unit level, you'll have to join the EUCG and participate in the study, which is ongoing.

By George W. Sharp, EUCG Inc., Fossil Productivity Committee

Even if you've never been in the market for a scrubber, you don't have to face management and vendors as a greenhorn. Thanks to the EUCG, you can enter meetings with valuable information about other utilities' costs—and how much your costs could rise between a scrubber's planning and operational phases.

The EUCG is an association of electric utility professionals that provides a forum in which utilities can improve their O&M practices and construction performance. Now in its 24th year, the EUCG holds technical conferences and workshops twice yearly for the purpose of information exchange. The organization (formerly known as the Electric Utility Cost Group) is organized into committees and working groups by interest area, such as fossil, nuclear, and hydroelectric plants; transmission and distribution; financial management; and, the latest—IT.

One of the EUCG's key activities is developing process and market benchmarks, unit reliability strategies, and best-practice applications to foster performance and cost excellence within the utility industry and competitive markets. The EUCG's Fossil Productivity Committee (FPC) has 32 electric utility members reporting operating data on more than 300 individual coal-fired units. That number represents more than 30% of operating coal plants in the U.S., so the data can be considered representative of the entire U.S. fleet.

FGD benchmarks

The need for flue gas desulfurization (FGD) began, as so many industry changes do, with the feds. The Clean Air Interstate Rule (CAIR), issued in early 2005, targeted 28 eastern states and the District of Columbia for significant SO_2 and NO_x reductions. When fully implemented, the EPA notes that SO_2 emissions will be reduced by 70% from 2003 levels. In fact, EPA projections show SO_2 will be reduced by 45% by 2010. Early estimates by the EPA (2004) placed the annual cost of CAIR compliance at around $2.9 billion in 2010 and $3.7 billion in 2015 for 49 GW worth of scrubbers.

The power industry has responded to CAIR with numerous major investments in FGD and selective catalytic reduction systems. In fact, demand has been so high that many vendors now find themselves unable to provide equipment to those arriving late to the party.

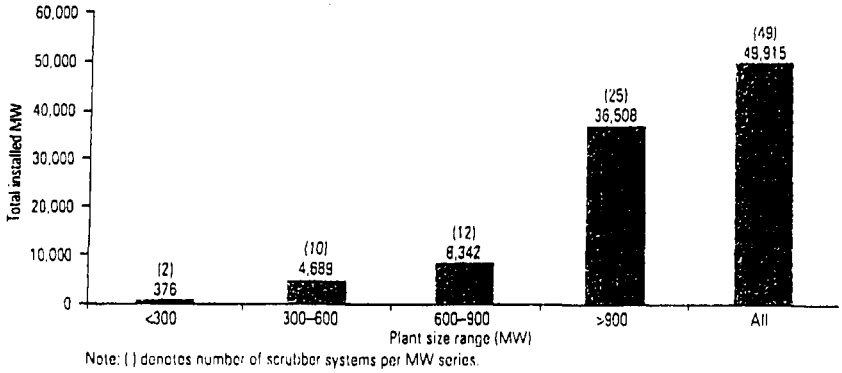
The FPC of the EUCG, responding to members' requests, designed and collected survey data on FGD technology and costs so members can benchmark their own facilities. The survey was conducted in early 2007, and detailed database results were provided to survey participants in March. The top-level results of that survey are presented exclusively to the readers of *POWER* as a service to the entire power industry.

The survey results have to be interpreted with a close eye to the peculiarities of each project site, and there are numerous factors that will influence costs and schedules. That said, it's not a surprise that costs are rising and competition for production slots in key vendor shops is keen. However, there are industry trends associated with FGD projects that may prove useful to those considering similar projects. Our purpose is to report on those trends and let you interpret the data in light of the complexities of your emissions compliance program.

And the survey says . . .

The FGD Survey data set covers over 70% of the forecasted FGD installations through 2012 (accounting for almost 50,000 MW) as published in a well-known industry consulting firm's recent market forecast for the same period (70,000 MW) (Figure 1). The 300-MW increment used in this summary report was selected to keep the data set reasonably sized, but the full report has much greater detail. The survey coverage is consistent with the magnitude of the instal-

1. Full coverage. The EUCG flue gas desulfurization (FGD) cost survey includes almost 50,000 MW and 49 units in a range of sizes. *Source: EUCG*



Note: ( ) denotes number of scrubber systems per MW series.

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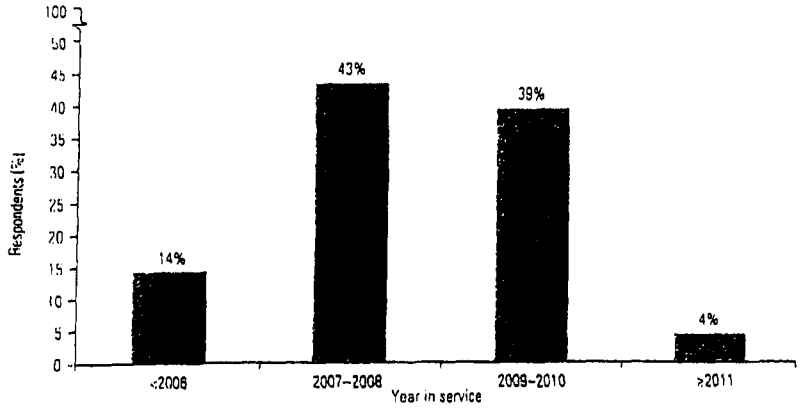
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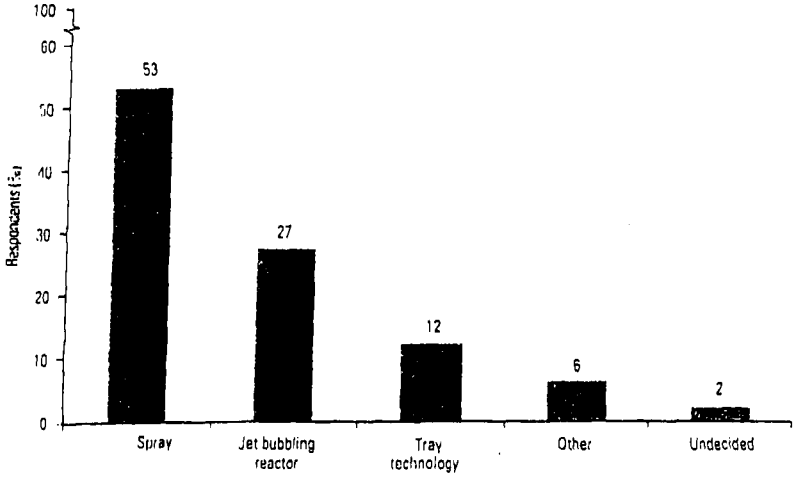
lations projected by the EPA, so the data set can be considered representative of the industry's experience (Figure 2).

A few background system design characteristics and assumptions are summarized below:

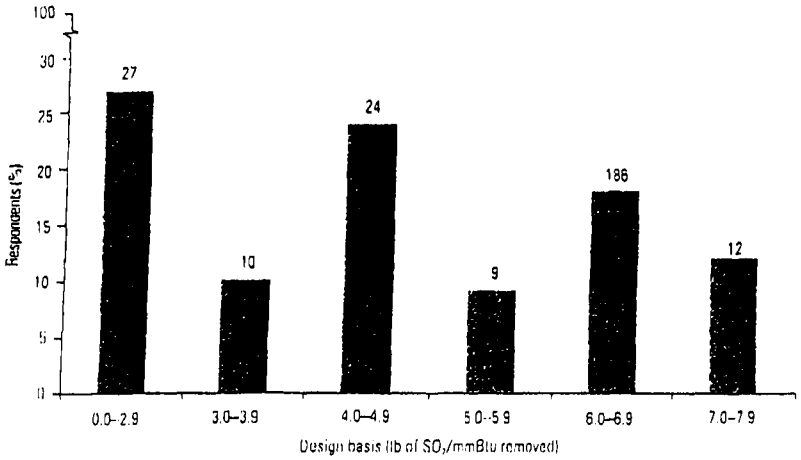
2. Full life cycle. The survey covers FGD projects from those in the planning stage through operating systems. *Source: EUCG*



3. Pick your flavor. FGDs with spray reactors were selected by over half of the respondents. *Source: EUCG*



4. Capture the SO_2. There is no consistency in the design basis for FGD systems among survey participants. Each company appears to have a different SO_2 removal strategy. *Source: EUCG*



- All the surveyed facilities are using limestone forced-oxidation technology.
- Tower technology selection varies by site, although more than half of the units chose spray technology (Figure 3).
- Over half of the respondents stated that their design includes a single-stack/double-flue configuration with another 41% specifying a single-stack/single-flue design. Only two plants reported using a single stack with more than two flues.
- There was more agreement with the flue material selection. At over 70% of surveyed plants the flue is fiberglass resin; 14% selected an alloy steel or C-276 clad flue.
- For FGD waste disposal, 53% of respondents are using an old or new landfill; slightly fewer (35%) are recycling at a wallboard plant.
- Reagent prep delivery is mostly by truck (51%), with the remainder using rail (29%) and marine vessel (20%).

These results will get you calibrated on the differences and similarities of FGD systems used in the study sample. Cost information follows in the second half of this article.

The design basis for the FGD survey reflected the wide variety of plants, locations, and fuels used in this industry. Survey results show that over 60% of the FGD systems were designed for less than 5 pounds SO_2/mmBtu (Figure 4). The average size of the plant was 1,019 MW, and the average on-line date was 2008.

Pay to play

Defining average project costs is difficult without getting into the details of each of the 49 plants surveyed, but one conclusion is obvious: Project costs are rising rapidly. Just a couple of years ago fixed-price, turnkey contracts were available for FGD projects. No more. Many contractors won't invest the time and money to prepare a cost-plus proposal without first negotiating a loss-on-ignition. It's a seller's market for major equipment and construction services.

The survey instructions requested that respondents define project costs for their just-completed, current, under construction, and/or planned FGD projects and to include the following line items, at a minimum, so that comparable data were reported:

- Project design costs
- New stack and ductwork costs
- Reagent prep method and costs
- Absorber island/reactor technology costs
- Site prep costs
- Wastewater treatment costs

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- Balance-of-plant (BOP) costs
- Other direct costs (such as engineering and project management)
- Associated boiler work (such as boiler modifications and upgrading fans)

The average FGD cost reported by the survey sample is $319/kW, an increase of 21% since the last FGD cost study completed in 2005. The survey also requested enough financial data so that the cost of just the FGD system could be identified without other site-specific costs, such as the stack and wastewater systems.

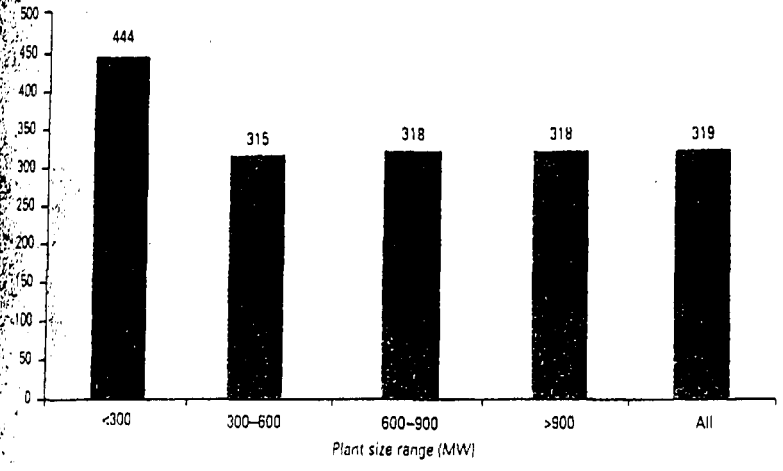
The result: The base cost of a FGD system was $243/kW. The equation used to determine the FGD cost alone was to sum the FGD absorber/reactor, reagent prep system, FGD waste disposal system, and BOP costs. Keep in mind that these are averages for 49 separate projects that are detailed further below. Participants in the survey receive the entire cost database so they can perform customized cost studies.

The next level of capital cost data gleaned from the survey data is the "cost by plant size range" (Figure 5). Notice that the so-called "fully loaded FGD" costs for plants rated at 300 MW and up were consistently just above $300/kW installed. We expected more economies of scale for such large projects, but the data disprove that assumption. Costs increased almost 50% for plants less than 300 MW, which shouldn't be a surprise.

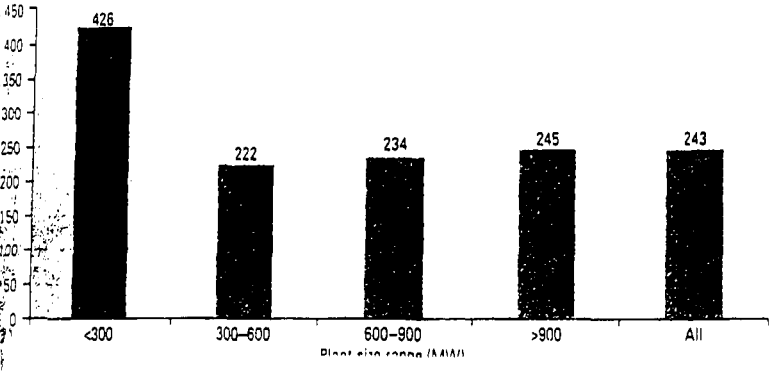
When the "FGD only" costs are extracted, installed costs do not seem to show any economy of scale but seem to still rise, although slightly, with increasing plant rating (Figure 6). The reason for the apparent disparity is not clear but may be due to the sample size per category, or perhaps the timing of the projects confounded the data.

Cost data were collected in such a way as to also enable an analysis based on project status. The 49 projects surveyed were in various stages of completion, ranging from preliminary engineering to operational. The fully loaded project costs show an interesting, but not unexpected, trend: "Older" projects cost significantly less than "new" projects (Figure 7). And the difference is not

5. **Size doesn't matter.** "Fully loaded" FGD system capital costs were reported by unit rating. *Source: EUCG*



6. **Costs are consistent.** "FGD system only" capital costs were also reported by survey respondents. Little difference in costs is seen with the larger plants. *Source: EUCG*



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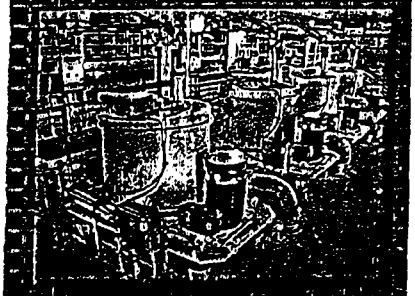
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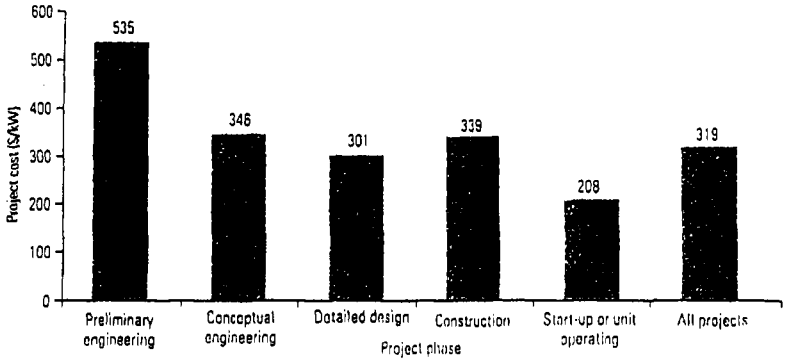
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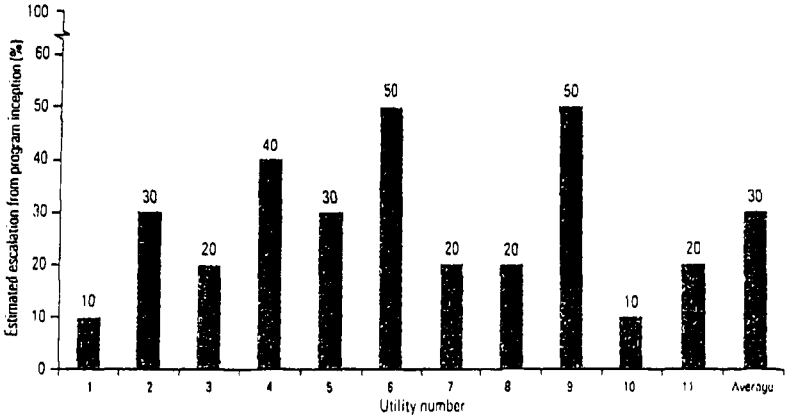
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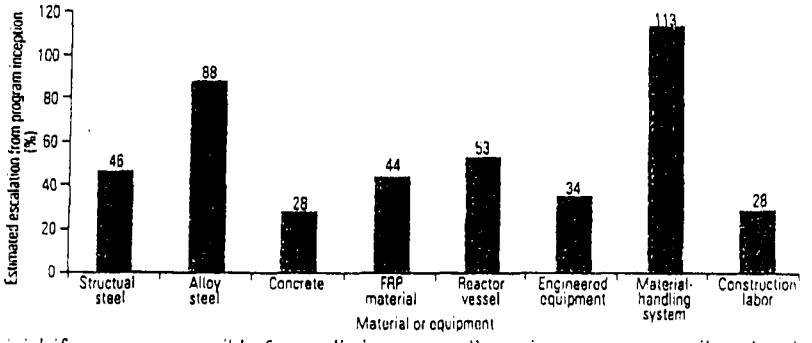
7. Going up. "Fully loaded" FGD system costs show large increases in costs between already-completed FGD projects and those in the planning phases. *Source: EUCG*



8. Inflation. Individual utilities report significant cost increases from suppliers since the inception of their FGD program. *Source: EUCG*



9. Big spenders. Cost increases experienced by each reporting utility were identified as falling into one of eight major categories. *Source: EUCG*



trivial if you are responsible for predicting what that next project will cost.

Costs are escalating

One consistent theme emerges from the 12 major utilities representing almost 50,000 MW of scrubber projects: FGD retrofit project costs are increasing rapidly, even during the phased construction of similar units within a single utility. An average 30% cost increase in supplier pricing was reported from the start to completion of one utility's multiple-unit FGD program (Figure 8). Slicing the data further reveals that the overall cost increases were attributed to the rising costs of alloy steels and the material-handling systems (Figure 9). Surprisingly, construction labor and concrete, showing a 28% increase, contributed the least to these increases. ●

—George W. Sharp heads business intelligence and commercial analysis for AEP's Power Generation Contract Administration business unit. He can be reached at gwsharp@aep.com. For more information about the EUCG, contact Pat Kovalesky, executive director, at 623-572-4140 or visit www.eucg.org.

PEF POD2 - 02136

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Rising Utility Construction Costs:

Sources and Impacts

Prepared by:

Marc W. Chupka
Gregory Basheda

The Brattle Group

Prepared for:



SEPTEMBER 2007

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Factors Spurring Rising Construction Costs

Broadly speaking, there are four primary sources of the increase in construction costs: (1) material input costs, including the cost of raw physical inputs, such as steel and cement as well as increased costs of components manufactured from these inputs (*e.g.*, transformers, turbines, pumps); (2) shop and fabrication capacity for manufactured components (relative to current demand); (3) the cost of construction field labor, both unskilled and craft labor; and (4) the market for large construction project management, *i.e.*, the queuing and bidding for projects. This section will discuss each of these factors.

Material Input Costs

Utility construction projects involve large quantities of steel, aluminum and copper (and components manufactured from these metals) as well as cement for foundations, footings and structures. All of these commodities have experienced substantial recent price increases, due to increased domestic and global demands as well as increased energy costs in mineral extraction, processing and transportation. In addition, since many of these materials are traded globally, the recent performance of the U.S. dollar will impact the domestic costs (see box on page 14).

Metals

After being relatively stable for many years (and even declining in real terms), the price of various metals, including steel, copper and aluminum, has increased significantly in the last few years. These increases are primarily the result of high global demand and increased production costs (including the impact of high energy prices). A weakening U.S. dollar has also contributed to high domestic prices for imported metals and various component products.

Figure 5 shows price indices for primary inputs into steel production (iron and steel scrap, and iron ore) since 1997. The price of both inputs fell in real terms during the late 1990s, but rose sharply after 2002. Compared to the 20-percent increase in the general inflation rate (GDP deflator) between 1997 and 2006, iron ore prices rose 75 percent and iron and steel scrap prices rose nearly 120 percent. The increase over the last few years was especially sharp—between 2003 and 2006, prices for iron ore rose 60 percent and iron and scrap steel rose 150 percent.

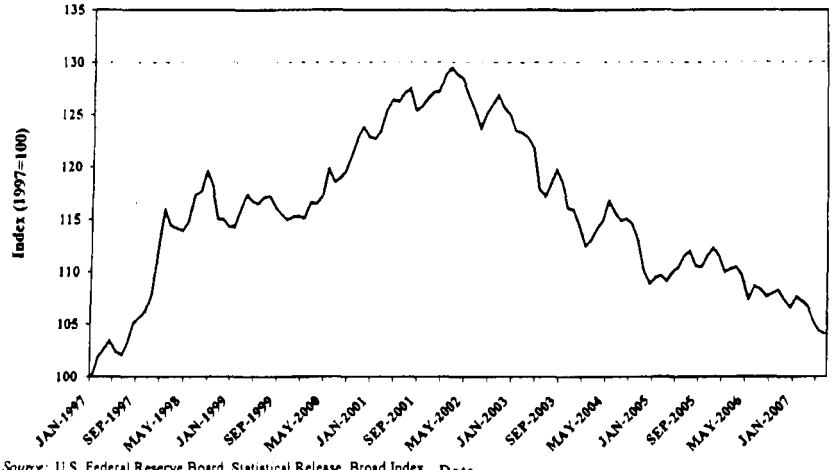
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Exchange Rates

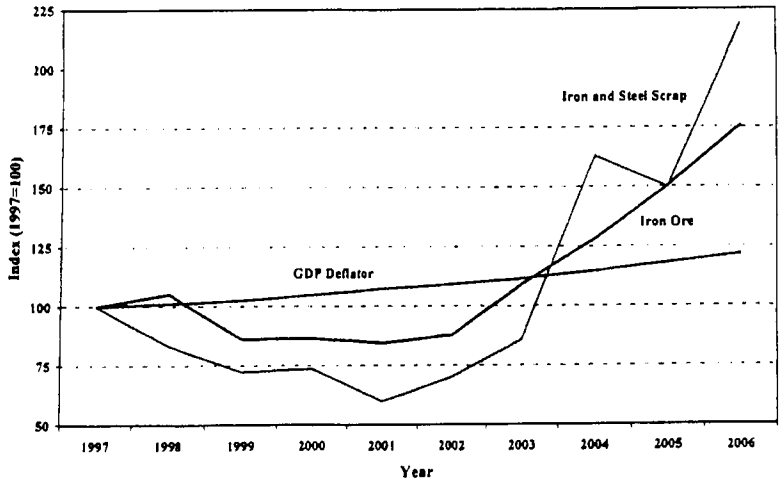
Many of the raw materials involved in utility construction projects (e.g., steel, copper, cement), as well as many major manufactured components of utility infrastructure investments, are globally traded. This means that prices in the U.S. are also affected by exchange rate fluctuations, which have been adverse to the dollar in recent years. The chart below shows trade-weighted exchange rates from 1997. Although the dollar appreciated against other currencies between 1997 and 2001, the graph also clearly shows a substantial erosion of the dollar since the beginning of 2002, losing roughly 20 percent of its value against other major trading partners' currencies. This has had a substantial impact on U.S. material and manufactured component prices, as will be reflected in many of the graphs that follow.

Nominal Broad Dollar Index



Source: U.S. Federal Reserve Board, Statistical Release, Broad Index Foreign Exchange Value of the Dollar

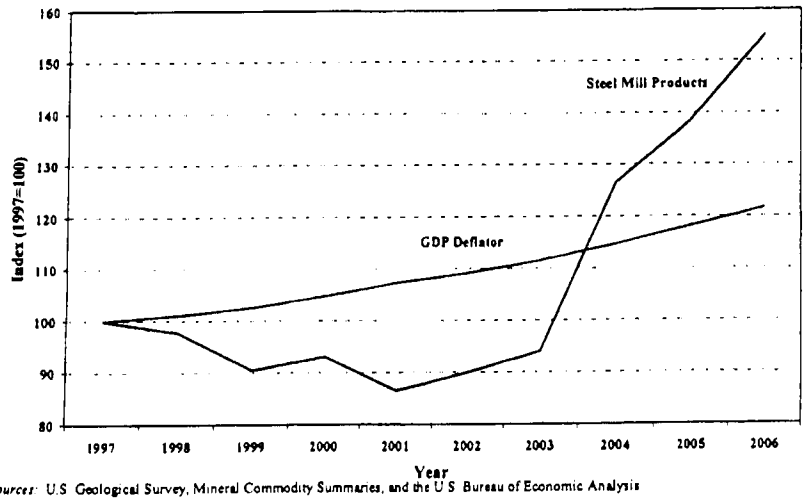
Figure 5
Inputs to Iron and Steel Production Cost Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis

The increase in input prices has been reflected in steel mill product prices. Figure 6 compares the trend in steel mill product prices to the general inflation rate (using the GDP deflator) over the past 10 years. Figure 6 shows that the price of steel has increased about 60 percent since 2003.

Figure 6
Steel Mill Products Price Index



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis

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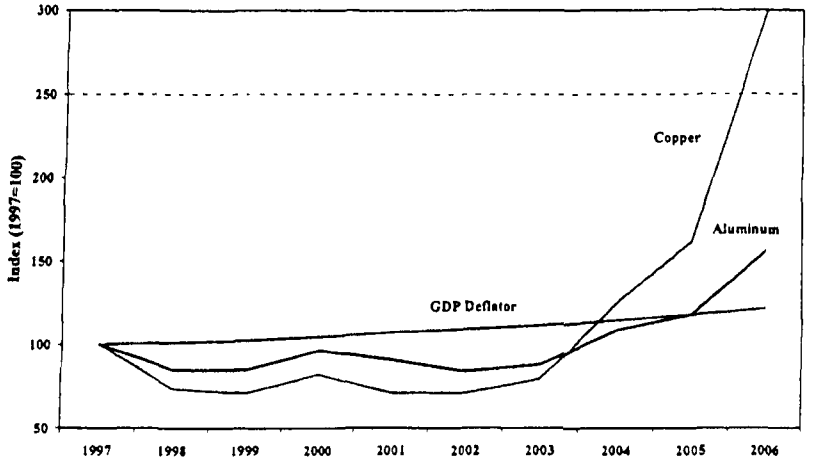
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Various sources point to the rapid growth of steel production and demand in China as a primary cause of the increases in both steel prices and the prices of steelmaking inputs.[11] China has become both the world's largest steelmaker and steel consumer. In addition, some analysts contend that steel companies have achieved greater pricing power, partly due to ongoing consolidation of the industry, and note that recently increased demand for steel has been driven largely by products used in energy and heavy industry, such as plate and structural steels.

From the perspective of the steel industry, the substantial and at least semi-permanent rise in the price of steel has been justified by the rapid rise in the price of many steelmaking inputs, such as steel scrap, iron ore, coking coal, and natural gas. Today's steel prices remain at historically elevated levels and, based on the underlying causes for high prices described, it appears that iron and steel costs are likely to remain at these high levels at least for the near future.

Other metals important for utility infrastructure display similar price patterns: declining real prices over the first five years or so of the previous 10 years, followed by sharp increases in the last few years. Figure 7 shows that aluminum prices doubled between 2003 and 2006, while copper prices nearly quadrupled over the same period.

Figure 7
Aluminum and Copper Price Indices

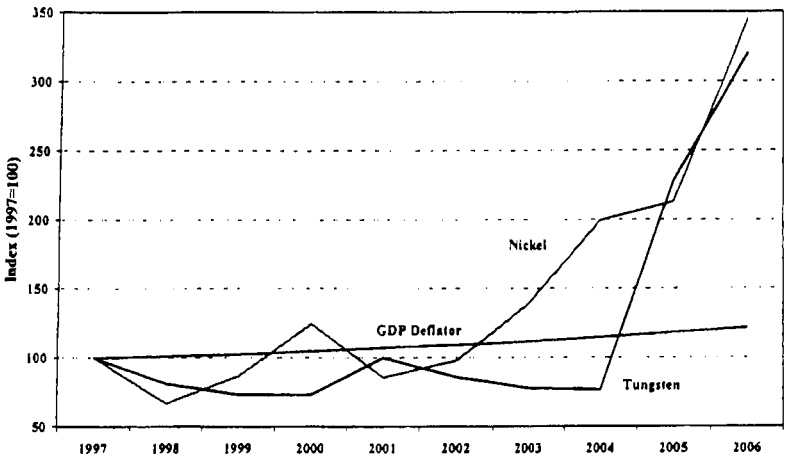


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis

[11] See, for example, *Steel: Price and Policy Issues*, CRS Report to Congress, Congressional Research Service, August 31, 2006.

These price increases were also evident in metals that contribute to important steel alloys used broadly in electrical infrastructure, such as nickel and tungsten. The prices of these display similar patterns, as shown in Figure 8.

Figure 8
Nickel and Tungsten Price Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis

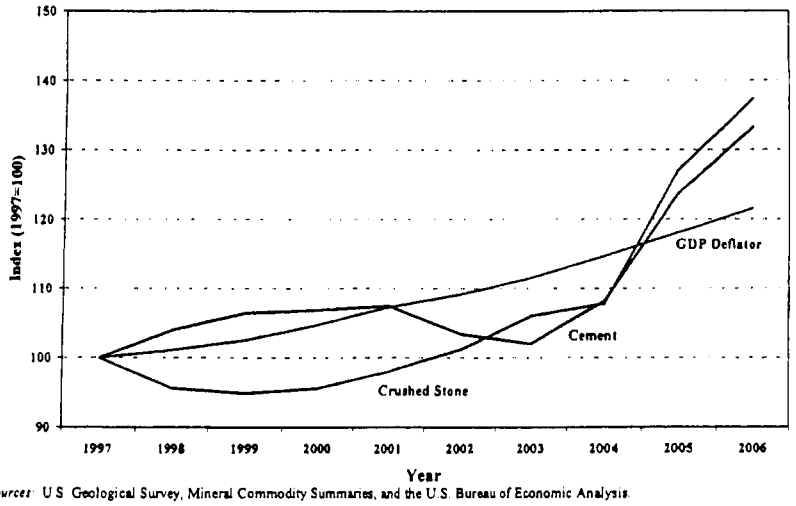
Cement, Concrete, Stone and Gravel

Large infrastructure projects require huge amounts of cement as well as basic stone materials. The price of cement has also risen substantially in the past few years, for the same reasons cited above for metals. Cement is an energy-intensive commodity that is traded on international markets, and recent price patterns resemble those displayed for metals. In utility construction, cement is often combined with stone and other aggregates for concrete (often reinforced with steel), and there are other site uses for sand, gravel and stone. These materials have also undergone significant price increases, primarily as a result of increased energy costs in extraction and transportation. Figure 9 shows recent price increases for cement and crushed stone. Prices for these materials have increased about 30 percent between 2004 and 2006.

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Figure 9
Cement and Crushed Stone Price Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

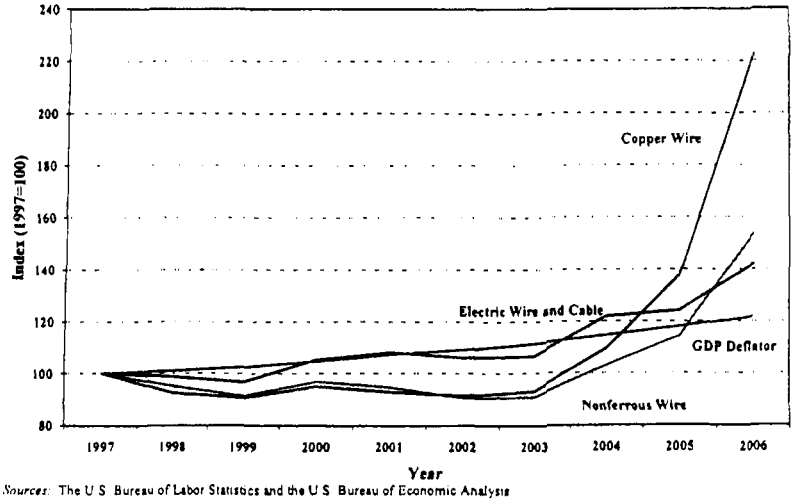
Manufactured Products for Utility Infrastructure

Although large utility construction projects consume substantial amounts of unassembled or semi-finished metal products (*e.g.*, reinforcing bars for concrete, structural steel), many of the components such as conductors, transformers and other equipment are manufactured elsewhere and shipped to the construction site. Available price indices for these components display similar patterns of recent sharp price increases.

Figure 10 shows the increased prices experienced in wire products compared to the inflation rate, according to the U.S. Bureau of Labor Statistics (BLS), highlighting the impact of underlying metal price increases.

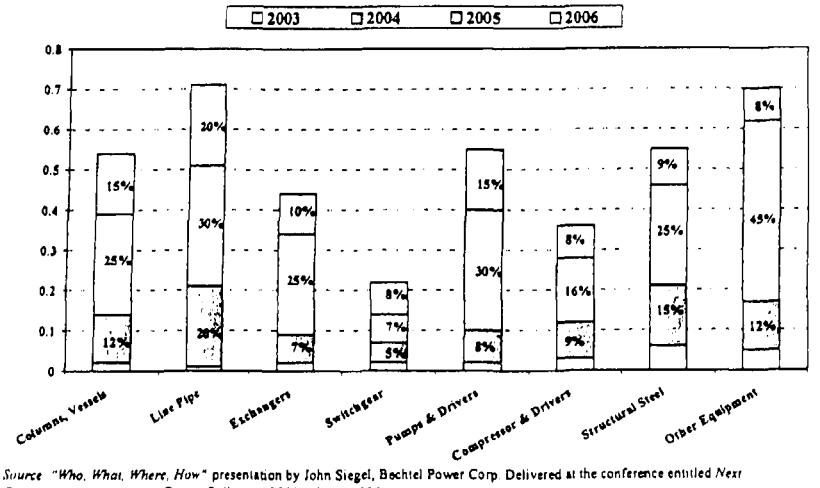
Manufactured components of generating facilities—large pressure vessels, condensers, pumps, valves—have also increased sharply since 2004. Figure 11 shows the yearly increases experienced in key component prices since 2003.

Figure 10
Electric Wire and Cable Price Indices



Sources: The U S Bureau of Labor Statistics and the U S Bureau of Economic Analysis

Figure 11
Equipment Price Increases



Source "*Who, What, Where, How*" presentation by John Siegel, Bechtel Power Corp Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

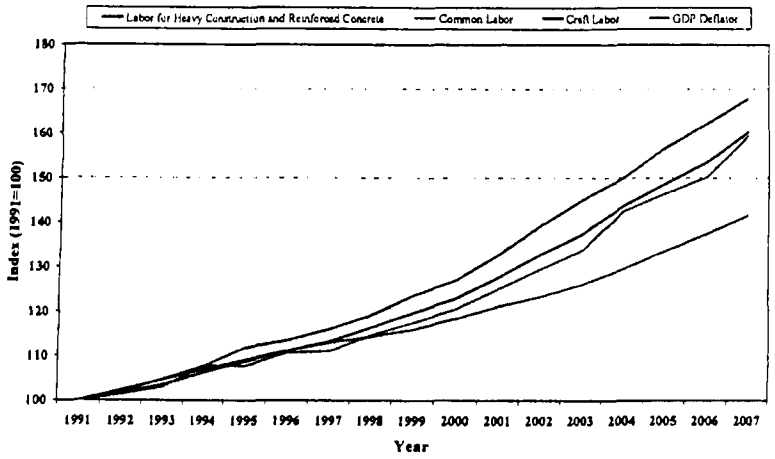
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Labor Costs

A significant component of utility construction costs is labor—both unskilled (common) labor as well as craft labor such as pipefitters and electricians. Labor costs have also increased at rates higher than the general inflation rate, although more steadily since 1997, and recent increases have been less dramatic than for commodities. Figure 12 shows a composite national labor cost index based on simple averages of the regional Handy-Whitman Index© for common and craft labor. Between January 2001 and January 2007, the general inflation rate (measured by the GDP deflator) increased about 15 percent. During the same period, the cost of craft labor and heavy construction labor increased about 26 percent, while common labor increased 27 percent, or almost twice the rate of general inflation.[12] While less severe than commodity cost increases, increased labor costs contributed to the overall construction cost increases because of their substantial share in overall utility infrastructure construction costs.

Figure 12
National Average Labor Costs Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional labor cost indices for the specified types of labor.

Although labor costs have not risen dramatically in recent years, there is growing concern about an emerging gap between demand and supply of skilled construction labor—especially if the anticipated boom in utility construction materializes. In 2002, the Construction Users Roundtable (CURT), surveyed its members and found that recruitment, education, and retention of craft workers continue to be critical issues for the industry.[13] The average age of the current construction skilled workforce is rising rapidly, and high attrition rates in construction are compounding the problem. The industry has always had high attrition at the entry-level positions, but now many workers in the 35-40 year-old age group are leaving the industry for a variety of reasons. The latest projections indicate that, because of attrition and anticipated growth, the construction

[12] These figures represent a simple average of six regional indices, however, local and regional labor markets can vary substantially from these national averages.

[13] *Confronting the Skilled Construction Workforce Shortage.* The Construction Users Roundtable, WP-401, June 2004, p. 1.

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industry must recruit 200,000 to 250,000 new craft workers per year to meet future needs. However, both demographics and a poor industry image are working against the construction industry as it tries to address this need.[14]

There also could be a growing gap between the demand and supply of electrical lineworkers who maintain the electric grid and who perform much of the labor for transmission and distribution investments. These workers erect poles and transmission towers and install or repair cables or wires used to carry electricity from power plants to customers. According to a DOE report, demand for such workers is expected to outpace supply over the next decade.[15] The DOE analysis indicates a significant forecasted shortage in the availability of qualified candidates by as many as 10,000 lineworkers, or nearly 20 percent of the current workforce. As of 2005, lineworkers earned a mean hourly wage of $25/hour, or $52,300 per year. The forecast supply shortage will place upward pressure on the wages earned by lineworkers.[16]

Shop and Fabrication Capacity

Many of the components of utility projects—including large components like turbines, condensers, and transformers—are manufactured, often as special orders to coincide with particular construction projects. Because many of these components are not held in large inventories, the overall capacity of their manufacturers can influence the prices obtained and the length of time between order and delivery. The price increases of major manufactured components were shown in Figure 11. While equipment and component prices obviously reflect underlying material costs, some of the price increases of manufactured components and the delivery lags are due to manufacturing capacity constraints that are not readily overcome in the near term.

As shown in Figure 13 and Figure 14, recent orders have largely eliminated spare shop capacity, and delivery times for major manufactured components have risen. These constraints are adding to price increases and are difficult to overcome with imported components because of the lower value of the dollar in recent years.

The increased delivery times can affect utility construction costs through completion delays that increase the cost of financing a project. In general, utilities commit substantial funds during the construction phase of a project that have to be financed either through debt or equity, called "allowance for fund used during construction" (AFUDC). All else held equal, the longer the time from the initiation through completion of a project, the higher is the financing costs of the investment and the ultimate costs passed through to ratepayers.

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[14] *Id.*, p. 1.

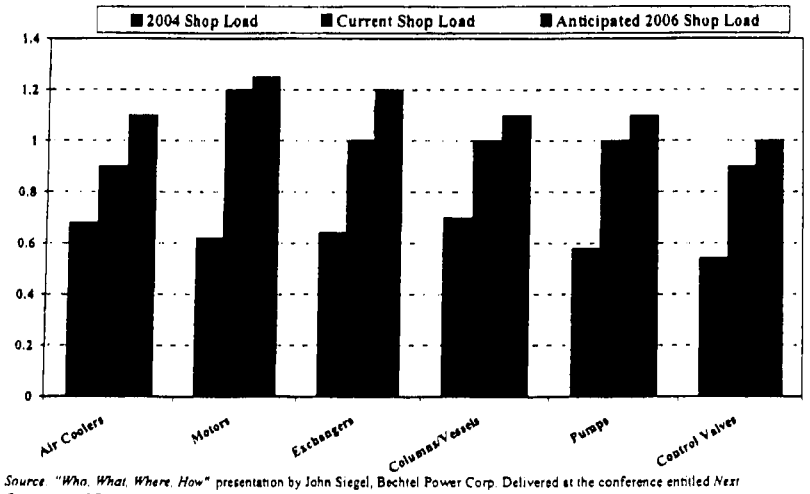
[15] *Workforce Trends in the Electric Utility Industry: A Report to the United States Congress Pursuant to Section 1101 of the Energy Policy Act of 2005*. U.S. Department of Energy, August 2006, p. xi.

[16] *Id.*, p. 5.

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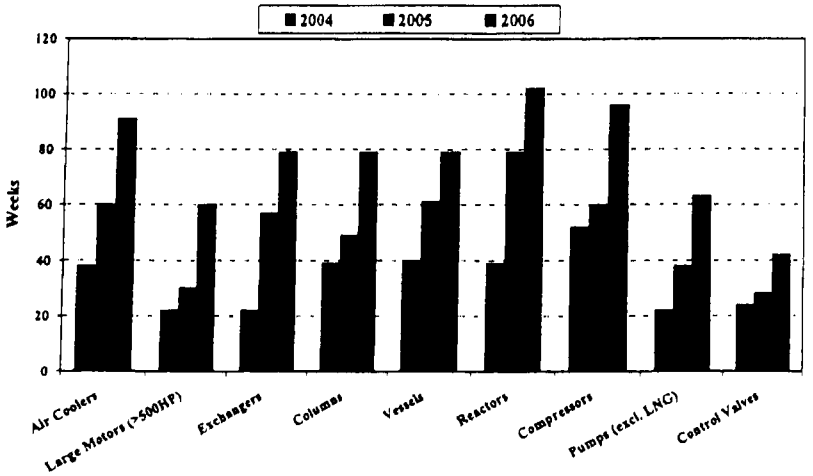
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Figure 13
Shop Capacity



Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Figure 14
Delivery Schedules



Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

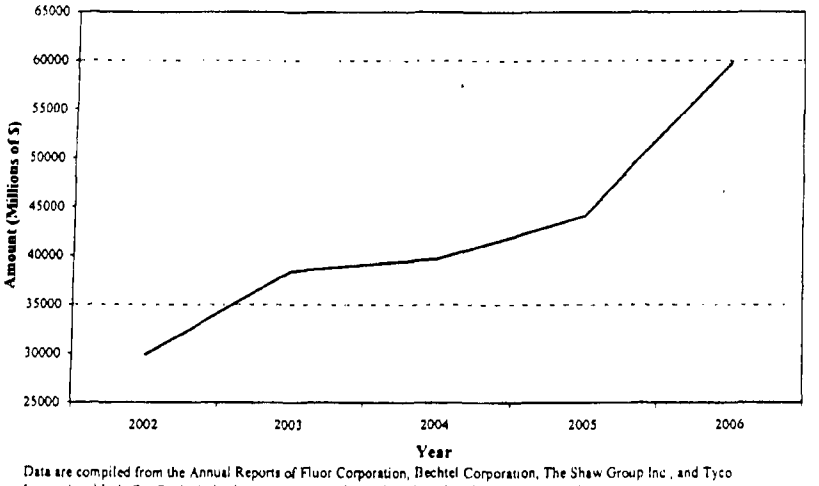
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Engineering, Procurement and Construction (EPC) Market Conditions

Increased worldwide demand for new generating and other electric infrastructure projects, particularly in China, has been cited as a significant reason for the recent escalation in the construction cost of new power plants. This suggests that major Engineering, Procurement and Construction (EPC) firms should have a growing backlog of utility infrastructure projects in the pipeline. While we were unable to obtain specific information from the major EPC firms on their worldwide backlog of electric utility infrastructure projects (*i.e.*, the number of electric utility projects compared with other infrastructure projects such as roads, port facilities and water infrastructure, in their respective pipelines), we examined their financial statements, which specify the financial value associated with their backlog of infrastructure projects. Figure 15 shows the cumulative annual financial value associated with the backlog of infrastructure projects at the following four major EPC firms; Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. Figure 15 shows that the annual backlog of infrastructure projects rose sharply between 2005 and 2006, from $4.1 billion to $5.6 billion, an increase of 37 percent. This significant increase in the annual backlog of infrastructure projects at EPC firms is consistent with the data showing an increased worldwide demand for infrastructure projects in general and also utility generation, transmission, and distribution projects.

Figure 15
Annual Backlog at Major EPC Firms



Data are compiled from the Annual Reports of Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. For Bechtel, the data represent new booked work, as backlog is not reported.

The growth in construction project backlogs likely will dampen the competitiveness of EPC bids for future projects, at least until the EPC industry is able to expand capacity to manage and execute greater volumes of projects. This observation does not imply that this market is generally uncompetitive—rather it reflects the limited ability of EPC firms with near-term capacity constraints to service an upswing in new project development associated with a boom period in infrastructure construction cycles. Such constraints,

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combined with a rapidly filling (or full) queue for project management services, limit incentives to bid aggressively on new projects.

Although difficult to quantify, this lack of spare capacity in the EPC market will undoubtedly have an upward price pressure on new bids for EPC services and contracts. A recent filing by Oklahoma Gas & Electric Company (OG&E) seeking approval of the Red Rock plant (a 950 MW coal unit) provides a demonstration of this effect. In January 2007, OG&E testimony indicated that their February 3, 2006, cost estimate of nearly $1,700/kW had been revised to more than $1,900/kW by September 29, 2006, a 12-percent increase in just nine months. More than half of the increase (6.6 percent) was ascribed to change in market conditions which "reflect higher materials costs (steel and concrete), escalation in major equipment costs, and a significant tightening of the market for EPC contractor services (as there are relatively few qualified firms that serve the power plant development market)."[17] In the detailed cost table, OG&E indicated that the estimate for EPC services had increased by more than 50 percent during the nine month period (from $223/kW to $340/kW).

Summary Construction Cost Indices

Several sources publish summary construction cost indices that reflect composite costs for various construction projects. Although changes in these indices depend on the actual cost weights assumed *e.g.*, labor, materials, manufactured components, they provide useful summary measures for large infrastructure project construction costs.

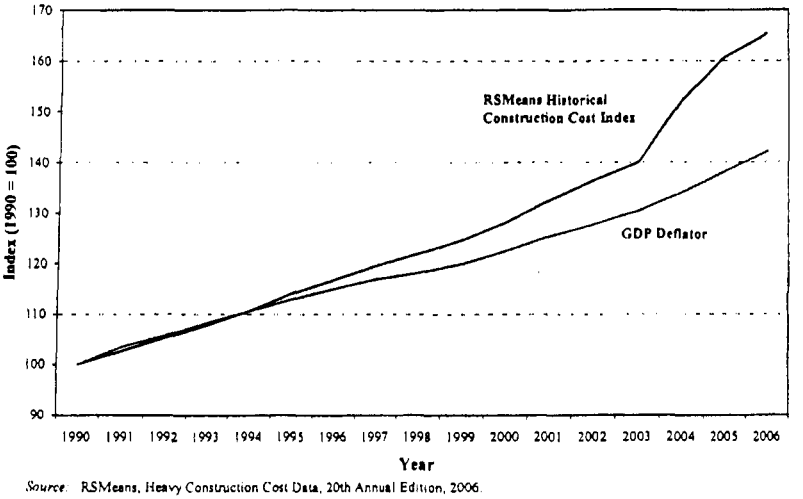
The RSMeans Construction Cost Index provides a general construction cost index, which reflects primarily building construction (as opposed to utility projects). This index also reflects many of the same cost drivers as large utility construction projects such as steel, cement and labor. Figure 16 shows the changes in the RSMeans Construction Cost index since 1990 relative to the general inflation rate. While the index rose slightly higher than the GDP deflator beginning in the mid 1990s, it shows a pronounced increase between 2003 and 2006 when it rose by 18 percent compared to the 9 percent increase in general inflation.

[17] Testimony of Jesse B. Langston before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200700012, January 17, 2007, page 27 and Exhibit JBL-9.

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Figure 16
RSMeans Historical Construction Cost Index



Source: RSMeans, Heavy Construction Cost Data, 20th Annual Edition, 2006.

The Handy-Whitman Index© publishes detailed indices of utility construction costs for six regions, broken down by detailed component costs in many cases. Figures 17 through 19 show the evolution of several of the broad aggregate indices since 1991 compared with the general inflation index (GDP deflator).[18] The index numbers displayed on the graphs are for January 1 of each year displayed.

Figure 17 displays two indices for generation costs: a weighted average of coal steam plant construction costs (boilers, generators, piping, etc.) and a stand-alone cost index for gas combustion turbines.

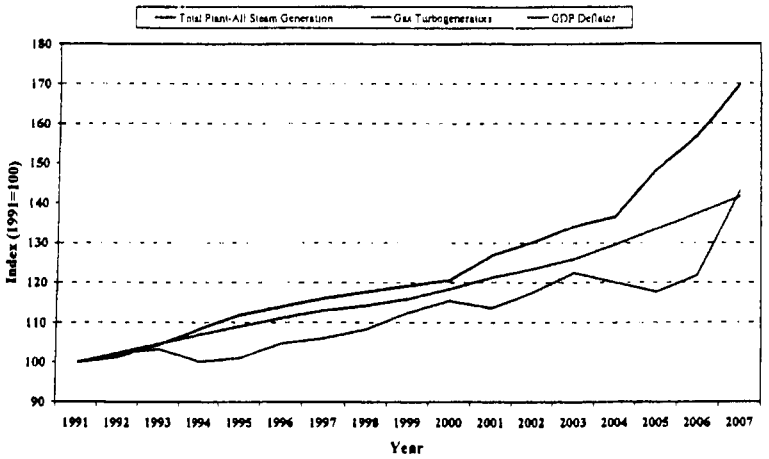
As seen on Figure 17, steam generation construction costs tracked the general inflation rate fairly well through the 1990s, began to rise modestly in 2001, and increased significantly since 2004. Between January 1, 2004, and January 1, 2007, the cost of constructing steam generating units increased by 25 percent—more than triple the rate of inflation over the same time period. The cost of gas turbogenerators (combustion turbines), on the other hand, actually fell between 2003 and 2005. However, during 2006, the cost of a new combustion turbine increased by nearly 18 percent—roughly 10 times the rate of general inflation.

[18] Used with permission. See Handy-Whitman© Bulletin, No. 165 for detailed data breakouts and regional values for six regions: Pacific, Plateau, South Central, North Central, South Atlantic and North Atlantic. The Figures shown reflect simple averages of the six regions.

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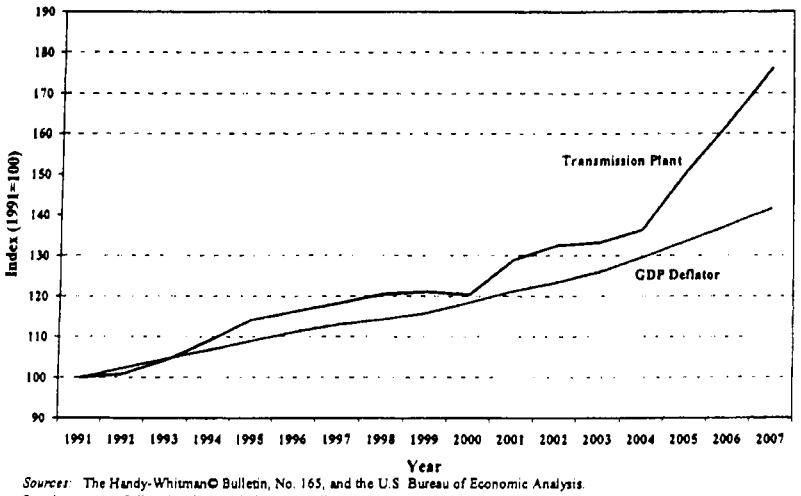
Figure 17
National Average Generation Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indices for the specified components

Figure 18 displays the increased cost of transmission investment, which reflects such items as towers, poles, station equipment, conductors and conduit. The cost of transmission plant investments rose at about the rate of inflation between 1991 and 2000, increased in 2001, and then showed an especially sharp increase between 2004 and 2007, rising almost 30 percent or nearly four times the annual inflation rate over that period.

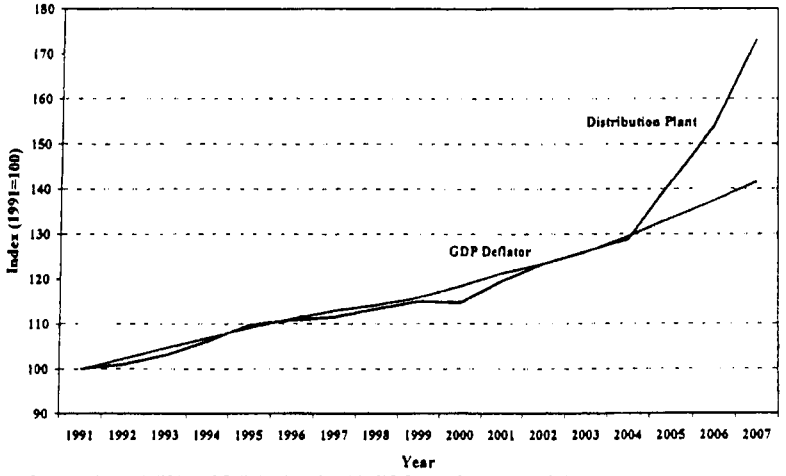
Figure 18
National Average Transmission Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional transmission cost indices

Figure 19 shows distribution plant costs, which include poles, conductors, conduit, transformers and meters. Overall distribution plant costs tracked the general inflation rate very closely between 1991 and 2003. However, it then increased 34 percent between January 2004 and January 2007, a rate that exceeded four times the rate of general inflation.

Figure 19
National Average Distribution Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis
Simple average of all regional distribution cost indices.

Comparison with Energy Information Administration Power Plant Cost Estimates

Every year, EIA prepares a long-term forecast of energy prices, production, and consumption (for electricity and the other major energy sectors), which is documented in the *Annual Energy Outlook* (AEO). A companion publication, *Assumptions to the Annual Energy Outlook*, itemizes the assumptions (*e.g.*, fuel prices, economic growth, environmental regulation) underlying EIA's annual long-term forecast. Included in the latter document are estimates of the "overnight" capital cost of new generating units *(i.e.*, the capital cost exclusive of financing costs). These cost estimates influence the type of new generating capacity projected to be built during the 25-year time horizon modeled in the AEO.

The EIA capital cost assumptions are generic estimates that do not take into account the site-specific characteristics that can affect construction costs significantly.[19] While EIA's estimates do not necessarily provide an accurate estimate of the cost of building a power plant at a specific location, they should, in theory, provide a good "ballpark" estimate of the relative construction cost of different generation

[19] EIA does incorporate regional multipliers to reflect minor variations in construction costs based on labor conditions.

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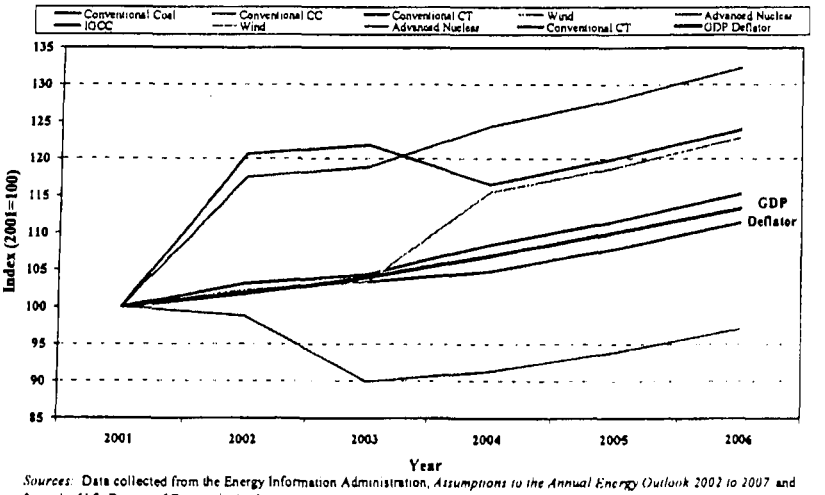
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technologies at any given time. In addition, since they are prepared annually, these estimates also should provide insight into construction cost trends over time.

The EIA plant cost estimates are widely used by industry analysts, consultants, academics, and policymakers. These numbers frequently are cited in regulatory proceedings, sometimes as a yardstick by which to measure a utility's projected or incurred capital costs for a generating plant. Given this, it is important that EIA's numbers provide a reasonable estimate of plant costs and incorporate both technological and other market trends that significantly affect these costs.

We reviewed EIA's estimate of overnight plant costs for the six-year period 2001 to 2006. Figure 20 shows EIA's estimates of the construction cost of six generation technologies—combined-cycle gas-fired plants, combustion turbines (CTs), pulverized coal, nuclear, IGCC, and wind—over the period 2001 to 2006 and compares these projections to the general inflation rate (GDP deflator). These six technologies, generally speaking, have been the ones most commonly built or given serious consideration in utility resource plans over the last few years. Thus, we can compare the data and case studies discussed above to EIA's cost estimates.

Figure 20
EIA Generation Construction Cost Estimates



Sources: Data collected from the Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

The general pattern in Figure 20 shows a dramatic change in several technology costs between 2001 and 2004 followed by a stable period of growth until 2006. The two exceptions to this are conventional coal and IGCC, which increase by a near constant rate each year close to the rate of inflation throughout the period. The data show conventional CC and conventional CT experiencing a sharp increase between 2001 and 2002. After this increase, conventional CC levels off and proceeds to increase at a pace near inflation, while conventional CT actually drops significantly before 2004 when it too levels near the rate of inflation. The

pattern seen with nuclear technology is near to the opposite. It falls dramatically until about 2003 and then increases at the same rate as the GDP deflator. Lastly, wind moves close to inflation until 2004 when it experiences a one-time jump and then flattens off through 2006.

These patterns of cost estimates over time contradict the data and findings of this report. Almost every other generation construction cost element has shown price changes at or near the rate of inflation throughout the early part of this decade with a dramatic change in only the last few years. EIA appears to have reconsidered several technology cost estimates (or revised the benchmark technology type) in isolation between 2001 and 2004, without a systematic update of others. Meanwhile, during the period that overall construction costs were rising well above the general inflation rate, EIA has not revised its estimated capital cost figures to reflect this trend.

EIA's estimates of plant costs do not adequately reflect the recent increase in plant construction costs that has occurred in the last few years. Indeed, EIA itself acknowledges that its estimated construction costs do not reflect short-term changes in the price of commodities such as steel, cement and concrete.[20] While one would expect some lag in the EIA data, it is troubling that its most recent estimates continue to show the construction cost of conventional power plants increasing only at the general rate of inflation. Empirical evidence shows that the construction cost of generating plants—both fossil-fired and renewable—is escalating at a rate well above the GDP deflator. Even the most recent EIA data fail to reflect important market impacts that are driving plant construction costs, and thus do not provide a reliable measure of current or expected construction costs.

[20] *Annual Energy Outlook 2007*, U.S. Energy Information Administration, p. 36.

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Conclusion

Construction costs for electric utility investments have risen sharply over the past several years, due to factors beyond the industry's control. Increased prices for material and manufactured components, rising wages, and a tighter market for construction project management services have contributed to an across-the-board increase in the costs of investing in utility infrastructure. These higher costs show no immediate signs of abating.

Despite these higher costs, utilities will continue to invest in baseload generation, environmental controls, transmission projects and distribution system expansion. However, rising construction costs will put additional upward pressure on retail rates over time, and may alter the pace and composition of investments going forward. The overall impact on the industry and on customers, however, will be borne out in various ways, depending on how utilities, markets and regulators respond to these cost increases. In the long run, customers ultimately will pay for higher construction costs—either directly in rates for completed assets of regulated companies, less directly in the form of higher energy prices needed to attract new generating capacity in organized markets and in higher transmission tariffs, or indirectly when rising construction costs defer investments and delay expected benefits such as enhanced reliability and lower, more stable long-term electricity prices.

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Comparison of Florida CAIR Costs
PEF vs. Gulf Power
As of April 1, 2007

System	Plant	Size	Cost		Plant	Size	Cost
Wet FGD	Crist (7 Units; 4-7 primarily impacted by CAIR; 1135MW (in service 2007-09)	~1000 MW for Units 4-7	$528M		CR 4 & 5 (in Se	1500MW	~$850M
Wet FGD	Smith Units 1-2 (in service 2013-18 – flexible plan)	340MW	$251M		(see above)		
Wet FGD	Daniel Units 1 & 2* (in service 2007 – 11)	500 MW (1000MW site)	$187M		(see above)		
Subtotal		***~1840MW***	***$966M***			***1500MW***	***$850M***
SCR	Crist Unit 6 (in service 2007 – 11)	~370 MW	$ 84M		CR 4 & 5	1500MW	~$250M
SCR	Daniel Units 1 & 2* (in svc 2012-17)	500 MW	$153M		(see above)		
Subtotal		***~870MW***	***$237M***			***1500MW***	***$250M***
SNCR	Smith Units 1 & 2 (in svc 2007-09)	340MW	$10M		n/a →		
SNCR	Daniel Units 1 & 2*	500 MW	$7M		n/a →		
Low NOx Burners	Daniel Units 1 & 2*	500 MW	$8M		Embedded in above		
Baghouse	Smith Unit 2	~170MW	$56M		n/a		
ESP's	n/a				CR 4&5	1500MW	~$100M
Subtotal other costs			***$81M***				***$100M***
Total estimated costs			***$1.28B***				***$1.20B***

PEF POD2 - 03252

Summary SO^2/ NOx Removal Costs

Gulf Power:

Plant Crist	~1000MW	$ 612M	Note only 1 SCR
Plant Smith	~340MW	$ 316M	FGD/ SNCR 2 Units; baghouse 1 unit
Plant Daniel	500MW	$ 355M	FGD, SNCR, SCR, LNB both units
Subtotal	*~1840MW*	*$ 1.28B*	
Plant Daniel	500 MW	$ 355M	Additional ownership portion
Total	*~2340 MW*	*$ 1.64B*	

PEF:

CR 4 & 5	1500MW	$ 1.10B	FGD, SCR, LNB both units
CR ESP's		$ 100M	ESP's at both units
Total	*1500MW*	*$ 1.20B*	

SEC/ FERC Notes

*Daniel is owned 50/50 with Mississippi Power – costs from Gulf Power filing were doubled to show estimated totals in summary information – SEC excerpts below on fossil gen & expected environmental costs

Crist	Pensacola, FL	970,000
Daniel	Pascagoula, MS	500,000 (6)
Lansing Smith	Panama City, FL	305,000
Scholz	Chattahoochee, FL	80,000
Scherer Unit 3	Macon, GA	204,500 (4)
Gulf Power Total		2,059,500

During 2006, 2005, and 2004, the Company recorded environmental cost recovery clause revenues of $40.9 million, $26.3 million, and $14.7 million, respectively. The construction program of the Company is currently estimated to be $146 million for 2007, of which $6 million is related to Hurricane Katrina restoration, $258 million for 2008, and $161 million for 2009. Environmental expenditures included in these amounts are $21 million, $91 million, and $82 million for 2007, 2008, and 2009, respectively.

B&W Awarded Contract to Supply and Construct Environmental Control Equipment

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HOUSTON, May 03, 2007 -- BUSINESS WIRE

McDermott International, Inc. (NYSE:MDR) announced today that its subsidiary, The Babcock & Wilcox Company ("B&W"), has received a contract for engineering, materials, construction, start-up and commissioning of environmental equipment at Allegheny Energy's Fort Martin Power Station near Maidsville, West Virginia. This contract will be included in B&W's second-quarter 2007 bookings.

For its share of the plant's **total $550 million project**, B&W will perform work on Fort Martin's two 550-megawatt supercritical coal-fired boilers -- Unit 1, started up in 1967, and Unit 2, originally supplied by B&W in 1968. B&W will supply wet flue-gas desulfurization ("WFGD") systems, commonly called scrubbers, for each unit including absorber areas and a common reagent preparation and dewatering system.

B&W's advanced WFGD systems operate by mixing a limestone slurry (reagent) with flue gas generated from the combustion of fossil fuel in large steam generators. B&W's WFGD system features include B&W's uniquely designed absorber module and B&W's patented flue gas distribution tray, which in combination are capable of achieving greater than 95 percent sulfur dioxide ("SO2") removal from plant emissions.

"B&W has a long-standing reputation as a leader in generating proven, reliable environmental solutions for the power industry," said Brandon C. Bethards, president of B&W's Fossil Power Group. "We've had a presence at the Fort Martin plant from its beginning, and this new order represents this customer's continued trust in B&W's technology and capabilities."

Engineering for the project is underway at B&W's Barberton headquarters. Mechanical completion of the units is slated for early spring of 2009, with start-up scheduled for the early fall of 2009.

B&W is also performing similar work at Allegheny Energy's Hatfield's Ferry Power Station, located in Masontown, Pennsylvania. The WFGD systems being installed on Hatfield's Ferry's three units are on schedule for completion in fall 2008.

Headquartered in Greensburg, Pennsylvania, Allegheny Energy is an investor-owned electric utility with total annual revenues of over $3 billion and more than 4,000 employees. The company owns and operates generating facilities and delivers low-cost, reliable electric service to over 1.5 million customers in Pennsylvania, West Virginia, Maryland and Virginia. For more information, visit our Web site at www.alleghenyenergy.com.

McDermott is an engineering and construction company, with specialty manufacturing and service capabilities, focused on energy infrastructure. McDermott's customers are predominantly utilities and other power generators, major and national oil companies, and the United States Government. With its global operations, McDermott operates in over 20 countries with more than 20,000 employees, and can be found on the internet at www.mcdermott.com.

In accordance with the Safe Harbor provisions of the Private Securities Litigation Reform Act of 1995, McDermott International, Inc. cautions that statements in this press release which are forward-looking and provide other than historical information involve risks and uncertainties that may impact McDermott's actual results of operations. The forward-looking statements in this press release include, among other things, work scope and timing associated with the Fort Martin Power Station project. Although McDermott's management believes that the expectations reflected in those forward-looking statements are reasonable, McDermott can give no assurance that those expectations will prove to have been correct. Those statements are made based on various underlying assumptions and are subject to numerous uncertainties and risks, including without limitation change orders and other modifications to contracts. If one or more of these risks materialize, or if underlying assumptions prove incorrect, actual results may vary materially from those expected. For a more complete discussion of these risk factors, please see McDermott's annual report on Form 10-K for the year ended December 31, 2006 filed with the Securities and Exchange Commission.

SOURCE: McDermott International, Inc.

PSEG Power to install emissions controls at 608 MW unit

19 July 2007 -- PSEG Power will install advanced emissions controls at its Hudson Generating Station coal-fired Unit 2 in Jersey City under terms of an amended environmental agreement reached last fall with state and federal regulators. Completion of the retrofits by 2010 will allow long-term, continued operation of the unit.

Hudson Unit 2 is a 608 MW coal unit. The work at Hudson includes installing selective catalytic reduction (SCR) for NOx reduction, flue-gas desulfurization (scrubber) for SO2 reduction, a bag house for particulate matter reduction and carbon injection for mercury control. The project will be completed by the end of 2010 and will cost between $700 and $750 million.

In January 2002, PSEG Power reached an agreement in the form of a Consent Decree with the New Jersey Department of Environmental Protection and the United States Environmental Protection Agency that called for installing the advanced emissions controls over a 10-year period. This agreement stemmed from discussions initiated by PSEG Power to resolve concerns over compliance with the New Source Review provisions of the federal Clean Air Act.

Shortly after the Consent Decree was finalized, however, significant changes in energy and capacity markets and increases in the cost of emissions control equipment and other necessary plant modifications called into question whether it would be more prudent to perform the work at Hudson or shut down the unit. The amended agreement required the company to make a decision by the end of 2007 whether to complete the environmental retrofit by the end 2010 or shut it down by 2008.

Progress Energy Florida's Responses to

Panel Deposition Transcript of Cornell/Waters 10/24/07 and Late Filed Exhibit No. 1

070007

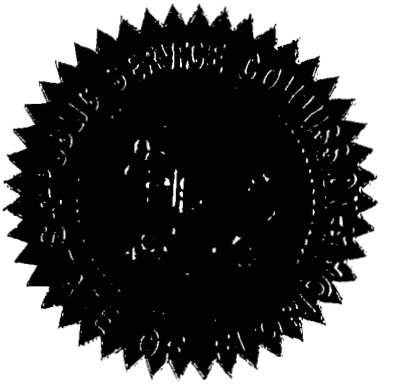
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070007-EI

In the Matter of

ENVIRONMENTAL COST RECOVERY CLAUSE.

_____/



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TELEPHONIC PANEL DEPOSITION OF:	THOMAS CORNELL and SAMUEL WATERS
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Room 382D Gerald L. Gunter Building 2540 Shumard Oak Boulevard Tallahassee, Florida
TIME:	Commenced at 1:34 p.m. Concluded at 2:20 p.m.
DATE:	Wednesday, October 24, 2007
REPORTED BY:	LINDA BOLES, CRR, RPR Official FPSC Reporter (850) 413-6734

070007-Hearing Exhibit 000357

APPEARANCES:

GARY V. PERKO, ESQUIRE, Hopping Law Firm, Post Office Box 6526, Tallahassee, Florida 32314, appearing on behalf of Progress Energy Florida, Inc.

JOHN W. MCWHIRTER, JR., ESQUIRE, representing Florida Industrial Power Users Group.

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

070007-Hearing Exhibit 000358

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EXHIBITS

NUMBER:		ID.
1	(Late-Filed) 2006 Progress Energy Report to Shareholders: An Assessment of Global Climate Change and Air Quality Risks and Actions	18

070007-Hearing Exhibit 000360

S T I P U L A T I O N

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

070007-Hearing Exhibit 000361

D E P O S I T I O N

MS. BROWN: We'll go on the record. This is the panel deposition of Witnesses Thomas Cornell and Samuel S. Waters in Docket Number 070007-EI, the environmental cost recovery clause. I am Martha Carter Brown representing the Commission staff. Gary and John, you want to give your appearance?

MR. PERKO: Sure. This is Gary Perko, P-E-R-K-O, of Hopping, Green & Sams Law Firm on behalf of Progress Energy Florida.

MR. McWHIRTER: John McWhirter, Jr., on behalf of the Florida Industrial Power Users Group.

MS. BROWN: All right. Thank you. Would the notary please swear in the witnesses.

THE NOTARY: Do I need to do them individually?

MS. BROWN: No, you don't need to. This is a panel depo. We can do them all at once.

Whereupon,

THOMAS CORNELL and SAMUEL WATERS

were called as witnesses, having first been duly sworn by the notary present with the witnesses, and testified as follows:

DIRECT EXAMINATION

BY MS. BROWN:

Q Good morning, Mr. Waters and Mr. -- oh, it's not morning. It's afternoon. Good afternoon.

070007-Hearing Exhibit 000362

Mr. Waters, would you state your name and business address for the record?

A (By Mr. Waters) Yes. My name is Samuel S. Waters. My business address is Progress Energy Carolinas, 100 East Davies Street, Raleigh, North Carolina 27601. And I should note that that address is different from my filed testimony. I've changed office locations since.

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

A I am employed by Progress Energy Carolinas as the Director of System Planning and Regulatory Performance.

Q You have filed direct testimony and exhibits in this docket regarding Progress's revised CAIR/CAMR/CAVR plan; correct?

A Yes, I have. Yes.

Q All right. Thank you.

And, Mr. Cornell, would you state your name and business address for the record?

A (By Mr. Cornell) Yes. My name is Thomas Cornell. My business address is 410 South Wilmington Street, Raleigh, North Carolina 27602.

Q And by whom are you employed and in what capacity?

A I am also employed by Progress Energy Carolinas as General Manager of Project Development and Engineering.

Q And you have filed direct testimony and supplemental

070007-Hearing Exhibit 000363

direct testimony and exhibits in this docket; correct?

A Yes, I have.

Q All right. Before we get to specific questions, I wanted to let you know that we have questions on five subjects related to Progress's CAIR/CAMR/CAVR plan. They are, one, PEF's analysis of coal to gas replacement of CR4 and 5 that you provided the Commission staff in response to its interrogatories. The second area is consideration of possible future CO2 capture and sequestration requirements. The third one is probabilities regarding the major cost drivers in Progress's integrated plan, specifically allowance prices. And, fourth, economies of scale, considerations in determining that Plan D remains the most cost-effective plan. And, finally, a few clarifying questions on bill impacts.

Since this is a panel deposition, whoever can respond best to the question, or if you both wish to respond, please feel free to do so. We believe we'll get more complete information that way. For the court reporter's sake though, at least in the beginning, would you please identify yourself when you speak.

And with that, we can go to the first set of questions we have, analysis of coal to gas replacement of CR4 and 5.

MR. PERKO: Martha, before you start --

MS. BROWN: Sure. Uh-huh.

070007-Hearing Exhibit 000364

MR. PERKO: On your fifth category, the bill impacts, you know, I'll wait until you ask the question, but I think we may not have the witnesses here to address those.

MS. BROWN: Well, they're pretty simple. Let me ask them, and then if not, we'll talk about that after the deposition.

MR. PERKO: That's fine.

MS. BROWN: Okay.

BY MS. BROWN:

Q Do you all have Progress's responses to Staff's Interrogatories Number 1 through 25 with you?

A (By Mr. Waters) Yes.

A (By Mr. Cornell) Yes, we do.

Q Okay. The response to Staff Interrogatory Number 11 contains the analysis PEF provided to show the economic impact of replacing the CR4 and CR5 coal units with natural gas generation; is that correct?

A (By Mr. Waters) Yes. Basically that's correct.

Q What is the source of the delivered fuel price forecast used to generate the analysis described in this response?

A Again, Sam Waters. The source of the fuel price forecast is our Regulated Fuels Department within Progress Energy.

Q Okay. So it's an in-house forecast that you all did?

070007-Hearing Exhibit 000365

A Well, let me clarify that. They provide the final forecast. They do use external sources to develop that forecast.

Q Do you know what external sources they use?

A I do not. I'm not familiar with all the sources they use. I think they verify as well as get input from external sources and they use them to verify the final forecast.

Q Okay. Is the fuel price forecast that they provided you the same fuel price forecast provided in your confidential response to Staff's POD Number 2, including the Anclote gas price forecast? Are those two the same?

A I'll take a quick look, but, yes, it should be.

Q Okay. Give me just a minute. I want to confer with my staff on one point. Just a second.

(Discussion held off the record.)

All right. Moving on.

A Just to confirm, yes, this is the forecast provided to us.

Q Okay. Thank you. What -- never mind. You already answered that.

Now just to confirm, that forecast is in nominal terms; correct?

A That is correct.

Q Okay. Did PEF analyze the impact of replacing CR Units 1 and 2 with gas-fired generation rather than

070007-Hearing Exhibit 000366

CR4 and 5?

A No, we did not.

Q And what was your reason for not doing that?

A Well, until the question was put to us in the interrogatories we really hadn't done an analysis of 4 and 5 either. The reason for that is we were looking at an overall corporate strategy from a resource planning perspective, and our compliance with potential CO2 regulations is being looked at in an overall corporate basis. We have a statement. In fact, a report was done to corporate shareholders in 2006 on our positions on global climate change and what we think ought to be done, but we have not done an analysis beyond what was presented in that, and certainly not in conjunction with this, the issue of the CAIR/CAMR compliance.

Q Okay. Well, we might want to come back to that when we get into our particular carbon capture questions.

A Okay. Yeah. We will come back to it I'm sure. Because one of the issues with trying to do that analysis is there are a variety of potential regulatory schemes. Just as an example, it might be carbon tax, it might be carbon capture that's required. We don't know exactly what regulatory scheme we'll be under. There are -- even under potential carbon tax scenarios and cap and trade scenarios there are a variety of bills before Congress that have very, very different pricing for carbon allowances and so on.

070007-Hearing Exhibit 000367

Q Sure.

A So there's such a wide range it makes it very difficult to have a basis for decision-making at this point.

Q But really we were just asking why you didn't do the same analysis for CR-1 and 2 that you did for CR4 and 5 with respect to natural gas.

A Well, the, the interrogatory was specifically aimed at Crystal River Units 4 and 5.

Q Okay.

A So we went ahead and did that case, but we didn't do any more than that.

Q Okay. Just a second.

(Pause.)

Okay. Would you turn to the last sentence of your response to Staff Interrogatory 11. It's on Page 4 of the responses. And basically we're just confused about the timing that you mention here. Can you clarify whether the analysis contemplates 2009 or 2017 as the replacement year for CR4 and 5?

A Sure. And I'll try to expand on the timing differences a little bit to hopefully clarify the situation. The analysis that was done for replacement of Crystal River Units 4 and 5 looked at replacement in 2017.

Q Okay.

A The reason we talk about 2009 in the interrogatory is

070007-Hearing Exhibit 000368

that the issue before us is trying to comply with CAIR regulations as well as CAMR and so on. But the CAIR regulations as far as NOx start in 2009.

Q Right.

A So our plan has, needs to address what we do with the 2009/10 time frame; whereas, CO2 -- just as an example, if I use Governor Crist's Executive Order, we're focused more on 2017. We did that for the purpose of the CO2 analysis. If we were talking about replacement in the 2009, that would almost be unfeasible at this point.

Q All right.

A I guess, again, just to further expand on that, if the root of the question is that we do the replacement of the unit instead of the scrubbing and adding SCRs, that would be also aimed, I guess, at meeting CAIR requirements. We would have to do that by 2009. That would be very difficult.

Q Okay. In Progress's coal to gas replacement analysis, you use that 2017 date. Was that because of the Governor's Executive Order?

A Yes. That was the primary driver there because it's the one thing we do have; whereas, a lot of the proposed legislation before Congress has varying dates.

Q Right. Would the cumulative present value revenue requirement be lower if an earlier year was selected, thereby avoiding a significant portion of the NOx and SO2 allowance

070007-Hearing Exhibit 000369

costs that increase beginning in 2009 and '10?

A No. You would be -- while you might be avoiding some of the allowance costs and so on, you would be spending the replacement money earlier. For example, let's assume that the combined cycles that replaced Crystal River 4 and 5 are roughly the same cost as the scrubbers. We have a PVRR presented in the report for the CAIR compliance. The PVRR I'm presenting here in the answer to the interrogatory is premised on those combined cycles being built by 2017. If I were to do it earlier, that would increase the present value by moving those units earlier. Yes. You would have some offset by avoiding some allowances and so on, but you would have the capital costs much earlier.

Q All right. Do you -- does the company have a written summary of its coal to gas replacement cost analysis showing the development of costs from your Strategist program, you know, some executive summary or high level recap of the analysis that was done?

A We do not beyond what is presented in the interrogatory. I used the raw Strategist results to develop that number. In other words, I just took the printout, the computer printout from the runs and, you know, did the subtraction on a calculator basically to come up with a number. So I don't have any write-up beyond what you see in the interrogatory.

070007-Hearing Exhibit 000370

Q All right. Is your estimated net cost of replacing CR4 and CR5, including the cost of environmental equipment with gas units, $6 billion less the $1.2 billion of the cost of the environmental equipment, and then you end up with a net of $4.8 billion would be the cost to replace Crystal Units 4 and 5 with gas?

A That is basically correct. But be careful with the $1.2 billion. If that is the capital expenditure, and I think that's what that number is, that is not a present value of revenue requirements. There is a present value of revenue requirements presented in the report, and I don't remember it from memory but I could look it up. But you need to use -- I think, is it Table 9 in the report that shows the revenue requirements of the various plans? I think it's Figure 9. That's the one you would want to use. So for Plan D it would be fifteen ninety is the number. That's the present value of revenue requirements. So you would use that to compare to the $6 billion.

Q Okay.

A So the net is about $4.5 billion.

Q All right. Well, let's move on to our second category, and we can talk some more about the carbon requirements. I'm not sure I really need to give this little speech because it sounds like you're willing to, to talk about this some, but we wanted to explore a little more with Progress

070007-Hearing Exhibit 000371

and their thinking and positions on carbon capture and their related costs and what effect those requirements may have on CAIR/CAMR. And we want you to know we agree that Progress faces actual existing CAIR/CAMR/CAVR regulations requiring certain compliance by 2009, and we acknowledge that most of the questions we have about carbon require speculation on Progress's part and answers that can't be supported by any solid facts and figures. Nevertheless, we want to discuss it because we think the Commissioners are concerned about it and we feel obligated to address the matter to some extent. So if you could try to answer these questions as completely as you feel comfortable with and as well as you can, and use all the qualifications and caveats that you want to just so we can get a little bit better understanding of Progress's views on this, this matter. Okay?

A Sure. Understood.

Q Okay. Is PEF a member of the Chicago Climate Exchange?

A This is Sam Waters. I really don't know the answer to that. I'm not involved in some of the group efforts that we may have joined.

Q Okay. So you're not aware whether Progress participates in any carbon allowance market activity?

A I am not.

Q Okay. Does Progress believe that carbon regulation

070007-Hearing Exhibit 000372

will be imposed on electric utilities in the U.S. during the time horizon considered in its analysis for CAIR/CAMR/CAVR?

MR. PERKO: Martha, I just need to insert an objection because this is not a corporate rep deposition. We can talk -- you know, you can ask Mr. Waters his knowledge, but I'm not sure that he can speak for the corporation.

MS. BROWN: Sure. Okay. All right.

BY MS. BROWN:

Q Well, to the extent that you can, Mr. Waters, is it your understanding that Progress thinks carbon regulation is on the horizon?

A I think, I think it would be fair to say that there's a high probability.

Q Okay.

A And the question is, is what form it might take. And before we -- I'm not trying to divert any of your questions, but do you have a copy of our 2006 report to shareholders on global climate change?

Q I don't think we do, and we would sure like it.

A Okay. I'd be glad to send you a copy. It's something we'll update in a study this year, but it gives --

MR. McWHIRTER: May I recommend that you make that as an exhibit to this deposition?

MS. BROWN: Yes. I was going to do that, Mr. McWhirter, but I didn't want to interrupt Mr. Waters in

070007-Hearing Exhibit 000373

mid-sentence.

MR. McWHIRTER: I don't mind doing that.

MS. BROWN: We'll make this Late-Filed Deposition Number 1.

(Late-Filed Exhibit 1 identified for the record.)

BY MS. BROWN:

Q And you said this was a climate change, 2006 climate change report to shareholders?

A Yeah. It's entitled, 2006, Progress Energy's Report to Shareholders, An Assessment of Global Climate Change and Air Quality Risks and Actions.

Q All right. That makes a great short title.

A Yeah. And I think that may help answer some of staff's questions. While I'm not in a position to speak for the corporation, I think the corporation has issued a report and talked about what potential actions lie ahead and what we would like to see in any legislation that's developed.

Q Uh-huh.

A And it talks, it also discusses what potential mitigation actions might be without choosing any in particular. It talks about what our options probably will be. It also in this report, which I think may be helpful, gives a projection of our CO2 emissions for PEF.

Q Yes. That, I think that would be helpful.

Anything else that it covers?

070007-Hearing Exhibit 000374

A Well, it's a fairly extensive document. It obviously covers quite a few things within its scope. It's, I'm trying to think, you know, a hundred pages or more of materials.

Q Uh-huh.

A So I think there's a lot of good information in here, and it really covers the company's position pretty well, I think.

Q All right. Well, that would be very helpful.

Back to your response to our Staff Interrogatory Number 11, we think we know the answer to this, but will you confirm for us that the CO2 annual emissions for Progress are not known for Plans A through F for any year in the forecast horizon that you use for the cumulative present value revenue requirement?

A I think it's correct in, in this sense: In running the model and calculating the production costs and the NOx and SOx emissions and mercury emissions and so on we did not track CO2 emissions in any of those cases.

Q All right. Thank you. Is it also correct that PEF does not know what actions it would likely take to comply with a set of environmental requirements similar to those included in, in Governor Crist's Executive Order?

Mr. Waters, you said earlier that, you mentioned the order. I assume you're familiar with it. I don't know if you have it before you or not.

070007-Hearing Exhibit 000375

A I do have a copy of it around here somewhere.

Q Okay. Well, we don't have a lot of extensive specifics about it, but we just wanted to know whether you had considered what actions you would take in case the future requirements were imposed similar to what Governor Crist is talking about?

A We do not know what specific actions we will take to comply with the Executive Order. I will say, going back to the shareholders' report that I referred to earlier --

Q Yes.

A -- there's a really good diagram that -- it's on Page 26 when you get a copy. I'll have to just kind of talk through it now. But I'll reference it, on Page 26, 25 and 26 it discusses Progress Energy Florida's emissions of CO2 for various alternative resource plans.

Q Yes.

A One of the things that it shows is that from -- it starts -- the graphs start in 2005. So they don't go back to 1990 as the baseline, but they start in 2005. And what they show is that the CO2 emissions profile out through about 2017 is relatively flat. And it also shows that if we add nuclear units to the system, which has been discussed, and certainly I think our plans at Levy County have been made public, with nuclear plants in the 2016/17 time frame, it actually creates a decline in CO2 system emissions.

070007-Hearing Exhibit 000376

And the reason I bring this up is that our resource plan itself may help at least in part meet the Governor's goals as well as conservation and so on, meaning we may not have to look to retirement of plants to meet it, although that may be an option. We just haven't decided yet. But we'll have to see once we finalize the resource plan and our DSM goals and so on where we end up and what we might yet have to do. The bottom line is I think it's premature to talk about retirement of any plants.

Q All right. And that was my next question. And I assume your answer is that you don't know which plants, if any, you would have to shut down if there were legislative limits on carbon emissions imposed.

A That's correct. We, we don't know. We haven't done the analysis. I will add to that though that looking at our proposed CAIR compliance plan where we're looking to add scrubbers and SCRs to Crystal River Units 4 and 5, it would probably make more sense to look at shutdown of Crystal River Units 1 and 2 first, the older units, and see what impact that might have on CO2 emissions before we look at CR4 and 5, because we're not at this point proposing to scrub Units 1 and 2.

Q Right. Going back to your CR4 and 5 natural gas replacement analysis, and you said the, sort of the bottom line figure was, what did you say, $4.5 billion to replace

070007-Hearing Exhibit 000377

CR4 and 5 with natural gas. Would carbon capture and sequestration costs have to exceed that number over the forecast horizon in order for replacement, replacement of CR4 and 5 to be cost-effective?

A We don't know the answer to that.

Q Okay.

A Because that's -- I think there's an assumption in your question that carbon sequestration is the only means of meeting CO2 targets that were not in a cap and trade environment.

Now, admittedly, the Governor's Executive Order is fairly specific, but federal legislation may occur that, for instance, creates a cap and trade system, creates a carbon tax system. Those are the things we don't know. So carbon sequestration might be just one option.

Q Uh-huh.

A And so when you say is it cost-effective, it may not matter because there may be other things we can do that are more cost-effective.

Q All right. Excuse me just for a minute and I'll be right back.

(Pause.)

All right. Thank you. That was very helpful.

Now to probabilities of major cost drivers, specifically allowance prices. On Page 8 of your testimony,

070007-Hearing Exhibit 000378

Mr. Cornell, at Lines 2 through 12, you talk about the fact that Plan A is the lowest cost plan under a high allowance cost forecast scenario. Excuse me?

A (By Mr. Cornell) I'm sorry, Martha. I didn't mean to interrupt, but I think that's Mr. Waters' testimony.

Q Oh, it is? I'm sorry. Well, I'm glad we did this deposition together. Have you found that Page 8?

A (By Mr. Waters) Yes. This is Mr. Waters. Yes, I have.

Q Okay. And Plan D in this testimony is the lowest cost plan under a base or a low allowance cost forecast scenario; is that correct?

A That's correct.

Q You have provided a confidential document that I want to discuss, and I don't think these questions are going to violate that confidentiality. But just to make you aware, if it looks like you think that's happening, stop me.

What probability, if any, does PEF place on its low base and high allowance price forecasts that the scenarios that are present in Figures 7 and 8 appearing on Page 27 of the Integrated Clean Air Compliance Plan? And that's the confidential version.

A We have not assigned a probability to the different forecasts.

Q Not at all?

070007-Hearing Exhibit 000379

A No, we have not. Generally speaking, when we do low and high band forecasts, we think of that as of presenting an 80 percent bound that the actual prices will occur somewhere between low and high.

Q All right.

A Now obviously this -- there's a, speaking in engineering terms, there's a feedback loop here that will influence the prices as we've seen this before, and it has a lot of different impacts.

If the, if the allowance prices fall towards the low end, then people look at the economics and tend to back away from scrubber projects or even SCR projects and say we'll buy allowances instead, which then increases demand on the allowances market, which forces them back into adding scrubbers and SCRs. So the pricing tends to be somewhat self-regulating, and we think, we believe that the base or most likely forecast, the middle forecast is the proper one to use for the analysis, knowing that prices will swing to some degree towards high and low depending on the decisions people make in meeting their, their own compliance goals.

Q All right.

A But in the long-term what we think is that that mid-band forecast is the correct forecast.

Q Okay. A couple of questions about economies of scale for, for scrubbers.

070007-Hearing Exhibit 000380

Are there economies of scale possible to install all FGD pollution controls for Crystal River 1, 2, 4 and 5 during the same period rather than installing the controls in different time periods?

A (By Mr. Cornell) Yeah. This is Tom Cornell.

Q Yes.

A If it was feasible at this point in time to do that for 1 and 2, yes, there would be economies of scale. The more units you can do on a dollars per KW scrubbed would be less.

Q And I guess you chose Plan D rather than Plan A because it wasn't feasible to scrub CR1 and 2 presently?

A (By Mr. Waters) This is Sam Waters. No. The -- I think it was chosen because it's least cost.

Q Okay.

A And that's the way we presented it. And it is least cost because when we look at the price to do 1 and 2. The flip side of that is 1 and 2 being smaller units, there tends to be some sort of, sort of inverse relationship. Smaller units tend to be more expensive to add scrubbers to. So the economics suggest Plan D, not the feasibility.

Q Okay. Hold on just a minute. We have about three more questions, if you'll just give us a second.

(Pause.)

Do you know how likely it is that scrubbers and SCR controls will be needed on CR1 and 2?

070007-Hearing Exhibit 000381

A This is Sam Waters. Difficult question to answer. The need for scrubbers on 1 and 2 can be driven by a change in regulations which we have no particular foresight on. That could occur. It could be driven obviously by the results suggest that if we track the high band allowance forecast, SO2 allowance forecast, then scrubbers would be economic. So there are a number of conditions. But as far as addressing the likelihood, that's very difficult. We don't think that that's the likely case right now. But our plan allows us to respond to that if conditions change, if we do see a significant change to the assumptions we've made.

Q And is, is that uncertainty in your minds the reason that you're foregoing the lower costs of Plan A that could be achieved from scale economies?

A Again, this is Sam Waters. I'm not sure I'm with you. Plan A is overall more costly than Plan D where you're talking about scrubbing all the units. Yes, it might provide some economy of scale on the capital side, but that additional capital that you're spending on 1 and 2, even with potential savings from economy of scale, is still more expensive overall when you take into account all the impacts than Plan D.

MS. BROWN: Okay. Mr. Waters, Gary, let's go off the record for a minute.

MR. PERKO: Sure.

MS. BROWN: Because I think I'm missing the point of

070007-Hearing Exhibit 000382

these questions that Bill is trying to answer. And if it's all right with you, he would like to clarify what he's trying to get at.

MR. PERKO: That's fine.

(Discussion held off the record.)

BY MS. BROWN:

Q Let's go back on the record then.

Mr. Waters, can you answer that for the record?

A Well, let me try to, and hopefully I won't confuse matters more.

The comparison in Figure 9 showing Plan A versus Plan F shows a lower CPVRR for Plan F than for Plan A. Part of the reason that it is lower or probably the main driver that it is lower is that the expenditures for Crystal River 1 and 2 are later in time, so they are more heavily discounted from a present value basis. So it makes the sum of the present day revenue requirements look lower even if the expenditures are higher for that. However, part of the impact that was captured here is if it is cheaper on a dollar-per-kilowatt-basis to do Plan A, that gets washed out in the net effect of timing. That's part of the problem here. We can't isolate the effect of the, whatever economy of scale we might get by doing all the units at roughly the same time because we have later expenditures and discounting going on that, that washes out the numbers.

070007-Hearing Exhibit 000383

MS. BROWN: All right. Thank you very much. One more question. Actually two more questions on bill impacts. And, Gary, you know, just let me know if you don't, you all don't think you can answer this.

The response to Staff Interrogatory Number 18 is what we're looking at. And in that response you have a numerical response which includes the expected charge for CAIR/CAMR compliance to customers based on annual dollars per thousand kilowatt hours; is that correct?

MR. PERKO: This is Mr. Perko. I believe so, yes. But I'd just point out, Martha, that these witnesses did not sponsor that response.

MS. BROWN: Okay. And so I guess they wouldn't know whether these dollars exclude the impact of CAVR costs or not. It's, it's a net. It's really not a big deal. Just a small question.

MR. PERKO: They're shaking their heads; they can't answer it.

MS. BROWN: All right. Well, thanks for trying. I think that's all the questions we have. If you'll give us a minute to see if we have anything else and then we'll be back on.

(Pause.)

Okay. That's all the questions we have. Gary, do you have any follow-up? Hello.

070007-Hearing Exhibit 000384

MR. McWHIRTER: McWhirter has no questions.

MS. BROWN: Thank you, John. I always forget you.

MR. McWHIRTER: Well, I'm sorry about that.

MS. BROWN: I am too.

Are you all still there? Are you back? Gary?

(Technical difficulties with phone connection.)

All right. Everybody back?

MR. PERKO: Yeah. Martha, I don't have any questions.

MS. BROWN: Okay. I was trying to track you down in Raleigh.

MR. PERKO: I apologize. We got cut off for some reason.

MS. BROWN: Well, then I think that concludes the deposition. If the notary could fax me the affidavit --

MR. PERKO: I think she already did.

MS. BROWN: Okay.

MR. PERKO: And they'll read, but we'll get you the errata quickly.

MS. BROWN: Okay. And thank you all very much.

(Deposition concluded at 2:20 p.m.)

070007-Hearing Exhibit 000385

ERRATA SHEET

DO NOT WRITE ON TRANSCRIPT - ENTER CHANGES HERE

IN RE: DOCKET NO. 070007-EI
NAME: THOMAS CORNELL
DATE: October 24, 2007

PAGE	LINE	CHANGE

ERRATA SHEET

DO NOT WRITE ON TRANSCRIPT - ENTER CHANGES HERE

IN RE: DOCKET NO. 070007-EI
NAME: SAMUEL WATERS
DATE: October 24, 2007

PAGE	LINE	CHANGE

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

I, LINDA BOLES, CRR, RPR, Official FPSC Commission Reporter, do hereby certify that I was authorized to and did stenographically report the foregoing deposition at the time and place herein stated.

I FURTHER CERTIFY that this transcript, consisting of 29 pages, constitutes a true record of the testimony given by the witness.

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 29th day of October, 2007.

Linda Boles

LINDA BOLES, CRR, RPR
Official FPSC Hearings Reporter
850/413-6734

070007-Hearing Exhibit 000388

CERTIFICATE OF OATH

STATE OF NORTH CAROLINA

COUNTY OF WAKE

I, the undersigned authority, certify that Thomas M. Cornell personally appeared before me at 410 S. Wilmington Street and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Raleigh, County of Wake, State of North Carolina this 24th day of October, 2007.

P D EDMISTON
NOTARY PUBLIC
WAKE COUNTY, N.C.
My Commission Expires 12-1-2007

P D Edmiston
Notary Public
State of North Carolina

Personally known X OR produced identification _____.

Type of identification produced _____.

CERTIFICATE OF OATH

STATE OF NORTH CAROLINA

COUNTY OF WAKE

I, the undersigned authority, certify that SAMUEL S. WATERS personally appeared before me at 410 S. Wilmington Street and was duly sworn by me to tell the truth.

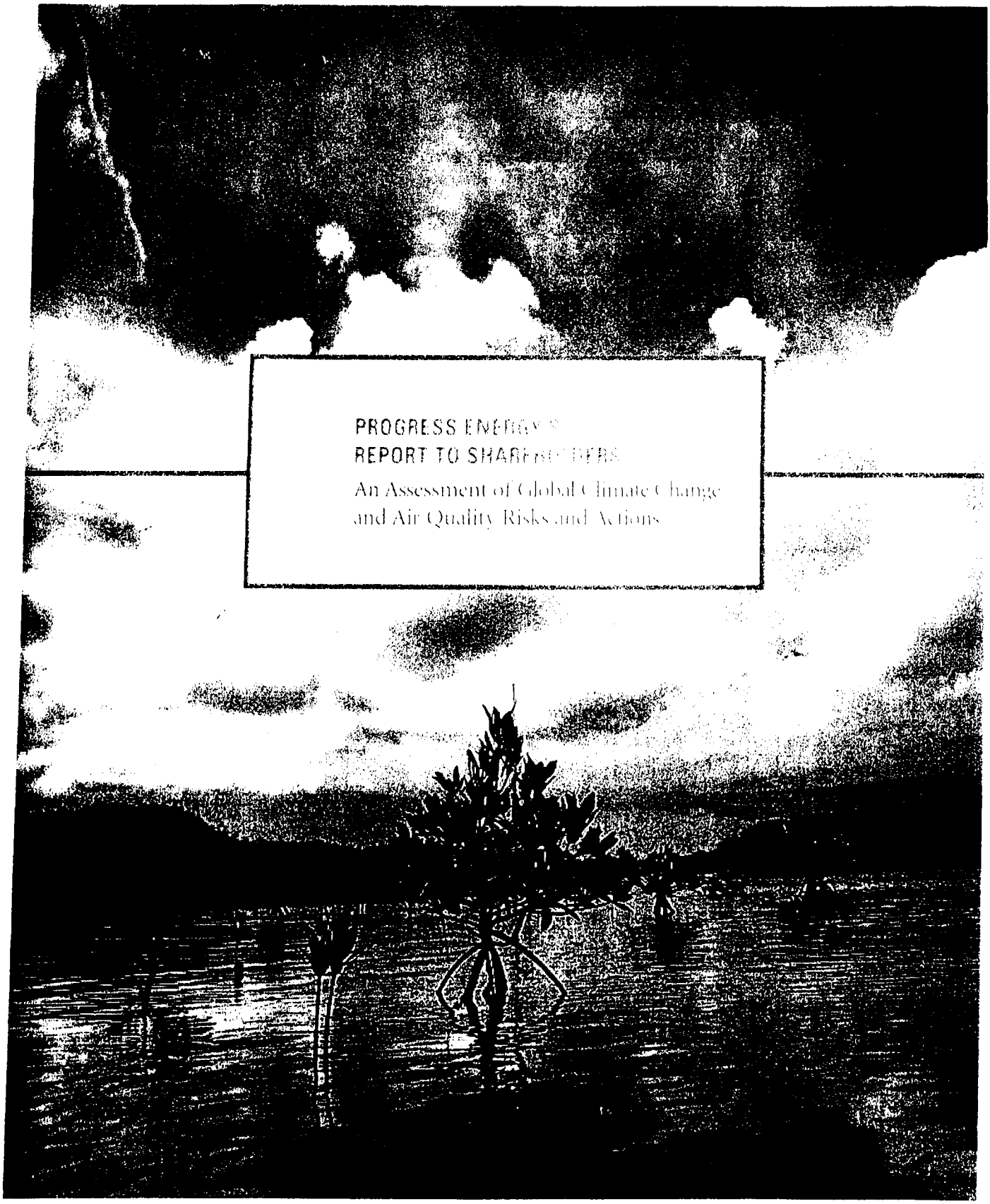
WITNESS my hand and official seal in the City of Raleigh, County of Wake, State of North Carolina, this 24th day of October, 2007.

P D EDMISTON
NOTARY PUBLIC
WAKE COUNTY, N.C.
My Commission Expires 12-1-2007

P D Edmiston
Notary Public
State of North Carolina

Personally known X OR produced identification _____.

Type of identification produced _____.



PROGRESS ENERGY'S
REPORT TO SHAREHOLDERS

An Assessment of Global Climate Change
and Air Quality Risks and Actions

Progress Energy

People. Performance. Excellence.

PENGAD 800-631-6989
EXHIBIT
Kate-Filed
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Carnell/Waters 10/29/07

ON THE COVER:

Weedon Island Preserve, located in St. Petersburg, Fla. Progress Energy's Bartow Plant is located on the island, which is adjacent to Tampa Bay. The company transferred a large portion of the island to Pinellas County to support the county's effort to expand a park. Portions of the island have also been designated as a manatee refuge.

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Introduction

At Progress Energy, we are strongly committed to the long-term success of our customers, shareholders and employees and to the future of the region we serve. Our company has many important responsibilities to fulfill, including reliable, affordable service, environmental stewardship and financial transparency.



With that in mind, and in response to a group of interested shareholders, we have prepared this report on the issue of global climate change. Progress Energy recognizes the importance of this issue, as well as its enormous scale and complexity. Even with considerable scientific uncertainties and the need for more research, we believe there is sufficient understanding of the issue and its potential consequences to warrant action by both the private and public sectors.

We believe that it is our responsibility to our shareholders to protect their investment in a possible carbon-constrained future. Also, as a corporate citizen whose prospects are closely tied to those of our local communities, we are committed to helping our region succeed in such a future.

This report describes our assessment of how constraints on carbon dioxide emissions and other air emissions might affect Progress Energy. It also describes our perspective on the global climate change issue, the steps we are already taking to address it and the mix of options we are evaluating. Realizing there is no one solution, we are taking a multipronged approach.

Our view is that policies to reduce carbon dioxide emissions must drive significant technological innovation on multiple fronts. These policies also must be comprehensive in that they address all sectors of the economy. They must be cost effective in that they are supported by rigorous economic analysis. And, finally, global climate change policies must be achievable in that the goals realistically can be met within the schedule envisioned.

We recognize that there are many approaches – both voluntary and mandatory – that have been discussed to address the climate change issue. We will evaluate any proposals to establish a national climate change policy based on how well they address our company's climate change principles, which are outlined in the executive summary and in section 7 of this report.

As we go forward, we will encourage the development of a national policy framework within which effective implementation can be achieved on a regional basis. Also, we will work actively with others at the state level to pursue consensus-based solutions, as we did successfully with the 2002 North Carolina Clean Smokestacks Act.

Progress Energy in 2006 is preparing for the future energy and environmental challenges of a high-growth region. Addressing them will require a balanced solution, including more conservation and efficiency programs, clean coal and nuclear technologies, and the development of new energy technologies.

The issue of global climate change will continue to unfold, and we will continue to evaluate and act on the best mix of options to address it. I hope you find this report helpful in understanding this important and challenging issue as it relates to our company.

Bob McGehee
Chairman and Chief Executive Officer

070007-Hearing Exhibit 000394

Message from shareholders

Progress Energy management and staff worked collaboratively with our shareholder group over the past 18 months to advance the company's position on climate change. The resulting report, which was reviewed by the company's board of directors, is an important step Progress Energy deserves to be proud of. This report, and the process the company undertook to produce it, demonstrates that Progress Energy is concerned about the impact of electricity consumption on the climate and will consider emission reduction strategies in fulfilling its mandate to supply reliable power in its territories. We are pleased the company has made commitments to address climate change and we look forward to monitoring its progress on these commitments in the years ahead.

Greenhouse gas emissions continue to rise from the electric sector and are projected to increase 43 percent between 2004 and 2030, according to the Energy Information Administration of the U.S. Department of Energy. The challenges of meeting electricity demand as we move into a carbon-constrained economy are complex, and key decisions regarding future power generation are being made today. We commend management for taking the following initial steps in this report, which publicly address these challenges and opportunities:

- Encourage development of national policy framework;
- Present relevant scenario analysis with clearly defined assumptions; and
- Affirm the company's commitment to reduce emissions from power production through support of new technologies.

We hope to continue our engagement in the following areas:

- Expand demand side management programs in North Carolina to surpass what the company has instituted in its Florida territory;
- Increase support of renewable energy potential including biomass, solar and wind; and
- Call for aggressive nationwide action to mitigate the risks of climate change and reduce greenhouse gas emissions.

As investors, we are aware that meeting future energy demand will require significant innovation, creativity and capital expenditures as we transition to a low-carbon economy. It is important for us to understand how Progress Energy is situated to meet growing future demand in a sustainable way. This is especially relevant as legislation favoring a carbon-constrained economy emerges, as it has for other pollutants under the North Carolina Clean Smokestacks Act, and federal action under the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) programs. This report is an essential tool for shareholders and others who will continue to evaluate Progress Energy on its ability to satisfy its mandate as we move forward into a carbon-constrained economy.

Sincerely,

The Brethren Benefit Trust
Boston Common Asset Management
Ceres
City of New York, Office of the Comptroller

070007-Hearing Exhibit 000395

Executive summary

In late 2004, a group of interested shareholders approached Progress Energy to learn more about the company's position on global climate change and other environmental issues and the future risks to the company of any greenhouse gas regulation or legislation.

This report addresses those issues, and the company has worked thoughtfully to develop its position. This report also lays out the key strategic issues facing the company, details existing company activities and research, and identifies potential steps the company could take to address these issues.

Key Strategic Issues

Progress Energy faces three key strategic issues in the coming years, each of which will play a role in the company's approach to climate change.

- **Fuel price volatility:** Progress Energy's priority is to provide energy that is reliable and affordable. The company generates electricity using coal, nuclear, natural gas, oil and renewable sources, such as hydroelectric plants. Thanks to this mix, the company is not overly dependent on a single source of energy.

High fossil fuel prices are impacting every aspect of the company's business. The company is responsible for managing these costs, and the state regulatory commissions that oversee the company's business must approve how costs affect customer rates.

The most abundant, reliable and cost-effective baseload fuel sources available to Progress Energy at this time are for coal and nuclear power generation. Using these sources helps to mitigate fuel cost impacts for customers and maintain fuel diversity.

Fossil fuel prices are likely to remain volatile, as shown by recent experience during the 2005 hurricane season, so the company's need to mitigate these costs will remain important.

- **Tightening clean air standards:** Progress Energy has already taken steps to reduce air emissions at its coal-fired plants in North Carolina as part of the state's Clean Smokestacks Act. Progress Energy joined a coalition of public officials, environmental organizations, citizen groups and businesses to support this law. This consensus-driven process has been viewed by other states as a positive example of collaborative environmental policymaking.

The Clean Smokestacks Act, however, is just the beginning. The federal Clean Air Interstate Rule (CAIR) requires significant reductions in emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) throughout the eastern United States, including Progress Energy's service areas in Florida and the Carolinas. At full implementation in 2015, CAIR would require a 70 percent cut in SO_2 emissions and a 65 percent reduction in NOx emissions from 2002 levels.

The federal Clean Air Mercury Rule (CAMR) requires reductions in mercury emissions in 2010 and 2018. This rule also sets up a trading program, which is particularly important because it is not known if technologies will be commercially available to meet emissions caps in 2018.

In June 2005, the U.S. Environmental Protection Agency issued the Clean Air Visibility Rule (CAVR). The rule requires states to identify facilities, including power plants, with the potential to produce emissions that affect visibility in specially protected areas. To help restore visibility in those areas, states must require the facilities to install Best Available Retrofit Technology (BART) to control their emissions. CAVR included EPA's determination that compliance with the NOx and SO_2 requirements of CAIR may be used by states as a BART substitute. Progress Energy expects that its plans to comply with CAIR and CAMR will fulfill BART obligations under CAVR.

In Florida and the Carolinas, Progress Energy is finalizing its plans to comply with these regulations.

- **Need for new baseload generation:** The third key strategic issue facing Progress Energy is customer growth and how the company will address that issue with new baseload generation.

070007-Hearing Exhibit 000396

Progress Energy is fortunate to operate in areas that are continually growing. Since Progress Energy last added baseload generation in the mid-1980s, its utilities in the Carolinas and Florida have grown by 1 million total customers, including about 73,000 in the year 2005 alone.

Meeting the energy demands of the future will require a balanced solution, including the development of new energy technologies and new clean coal and nuclear plants.

In addition to looking at new generation, the company has also instituted conservation and efficiency programs to help customers reduce their usage. For example, since 1981, the company's energy-efficiency programs have reduced energy usage by more than 26 billion kWh.

Energy-efficiency and conservation programs will continue to play a role in Progress Energy's planning, and those programs will address some of the growth. The company will need to do much more to keep up with customer and demand growth.

Key Points of Progress Energy's Position on Global Climate Change

Policies to address global climate change present business risk to Progress Energy and social, economic and environmental risks to the areas we serve. Even with the considerable scientific uncertainties about this issue, we believe there is sufficient understanding to warrant action by both the private and public sectors. While continuing to fulfill our obligation to provide reliable, affordable electric service to our customers, we are taking action on this important issue as part of our strong commitment to environmental stewardship and responsible corporate citizenship.

Progress Energy believes in the following principles:

- Climate change policies should be comprehensive in that they include all sectors of the economy, cost effective in that they are supported by rigorous economic analysis, and achievable in that the goals and schedule are realistic.
- Climate change policies should be designed to promote substantial technological innovation on multiple fronts and timely, cost-effective deployment of technologies.
- Climate change policies should not harm the economy or our ability to provide reliable, affordable electric service to our customers.
- Climate change policies should promote fuel diversity by encouraging renewable energy, advanced nuclear, gas and clean coal technologies.
- The global nature of climate change requires a national policy framework, informed by international developments and commitments.
- The country's regional differences require flexibility in the implementation of policy solutions.
- While participating in the national policy debate, we will work with stakeholders in our region to develop consensus-based strategies to address climate change and help our region succeed as future national policies are implemented.

Any proposals to establish a national climate change policy should be evaluated based on how well they address these climate change principles.

070007-Hearing Exhibit 000397

Company Activities and Research

While Progress Energy will address the risks associated with global climate change on its business in the coming years, the company has already taken many steps to mitigate that risk, including:

- **Nuclear uprates:** Since 2001, Progress Energy has completed uprates totaling about 315 MW at its nuclear plants in the Carolinas and Florida, avoiding more than 36 million tons of carbon dioxide emissions.

- **Fossil plant optimization projects:** Progress Energy has undertaken optimization projects at its fossil plants, including the Mayo Plant in Person County, N.C., and the Sutton Plant in Wilmington, N.C., reducing carbon dioxide emissions and increasing plant efficiency.

- **Energy-efficiency projects:** Progress Energy has robust energy-efficiency programs in the Carolinas and Florida, and an aggressive demand side management (DSM) program in Florida. Since 1981, energy-efficiency programs have helped the company avoid more than 16 million tons of carbon dioxide emissions.

- **Renewable and alternative energy development and research:** Progress Energy has four hydroelectric plants in North Carolina, capable of producing 218 MW of electricity. In addition, the company has partnered with government and private entities on solar, fuel cell and hydrogen projects.

  Progress Energy also supports NC GreenPower, a statewide program that encourages the development of renewable energy. More than 7,500 utility customers, including almost 2,300 Progress Energy customers, voluntarily pay $4 or more on their monthly bills to subsidize the purchase of renewable energy for the grid. About 20 renewable energy generators are under contract or operating under this program.

- **Other carbon dioxide-reduction efforts:** The company supports the University of North Carolina at Chapel Hill's Sustainable Energy, Environment and Economic Development (SEEED) project and is partnering with the Southern States Energy Board, the Electric Power Research Institute (EPRI) and other utilities on a carbon sequestration project in the Carolinas.

Future Climate Change Options

No single solution will address the issue of climate change. Progress Energy must consider all potential solutions in the southeastern United States, including:

- **Clean coal technologies:** Progress Energy is considering integrated gasification combined cycle (IGCC) technology and will continue to monitor its advancement. In addition, the company has conducted studies to look at the possibility of using advanced pressurized fluidized-bed combustion and circulating fluidized-bed combustion at two of its plants in North Carolina. These technologies use air, injected through the bottom of the furnace, to mix coal and a sulfur-absorbing material, such as limestone or dolomite, during combustion. Supercritical coal plants, which use a much higher pressure steam and temperature in the combustion process and produce fewer emissions, have also been considered by the company in its annual planning. While no decisions have been made to employ these options at this time, they remain under consideration.

- **Repowering existing generation units:** The company is repowering its Bartow Plant near St. Petersburg, Fla., from an oil-fired facility to a natural gas-fired power plant. The company is also considering repowering other plants in its service territory.

- **Renewables:** Potential for co-firing biomass exists in Progress Energy's service area, and the company is on track to begin its first biomass co-firing trial at the Sutton Plant in Wilmington, N.C., in 2006. The potential for animal waste co-firing has an additional benefit of reducing environmental impacts associated with North Carolina's current animal waste disposal methods.

- **Expanded efficiency projects:** Progress Energy is looking at aggressive promotion and expansion of existing energy-efficiency programs, including strengthening demand side management programs. The company is committed to working with regulators and stakeholders to develop cost-effective energy efficiency and demand side management choices for its customers.

070007-Hearing Exhibit 000398

- New nuclear generation: The company informed the Nuclear Regulatory Commission in August 2005 that it plans to submit a combined license application for a new nuclear plant. It updated those plans in November 2005 to include a second application – one for the Carolinas and one for Florida. Each application covers up to two reactors at each site. The licensing process, once completed, gives the permit holder the option to construct and operate units on a specific site – it does not obligate the company to build.

In January 2006, the company announced that it would evaluate the Harris Nuclear Plant site near New Hill, N.C., for possible future nuclear generation expansion. Progress Energy chose the Harris site after evaluating several sites in the Carolinas, based on its available land, transmission lines and proximity to cooling water and to Progress Energy Carolinas' largest area of customer concentration. The company expects to select a site in Florida in the first part of 2006.

A final decision to build another nuclear plant is still several years away. It will be based on many factors, including public and political support, regulatory approval and forecasts for energy demand and economic conditions later this decade. In order to provide the most reliable and affordable mix of energy resources for its customers, Progress Energy is taking steps now to keep the option for nuclear open and viable in the future.

Conclusion

Progress Energy recognizes that global climate change is a significant issue that presents business risk to the company, as well as social, economic and environmental risks to the areas it serves. In addressing this issue, the company must balance economic and environmental issues with its obligation to provide affordable, reliable electricity to its customers. To achieve these objectives, the company will employ a multipronged, balanced approach by boosting conservation and efficiency programs, increasing the use of renewable sources of energy and using nuclear power and potentially clean coal technologies to address demand and customer growth.

070007-Hearing Exhibit 000399

Company background

Progress Energy (NYSE: PGN), headquartered in Raleigh, N.C., is a Fortune 250 diversified energy company with more than 24,500 megawatts of generation capacity and $10 billion in annual revenues. The company's holdings include two electric utilities serving approximately 3 million customers in North Carolina, South Carolina and Florida. Progress Energy also has nonregulated operations, including competitive generation, energy marketing, natural gas production and fuel extraction.

Progress Energy operates under an integrated energy model – involving the generation, transmission and distribution of electricity in both regulated and competitive markets. The company's service territory covers more than 34,000 square miles in the Carolinas and more than 20,000 square miles in Florida, with more than 98,000 miles of distribution lines and 11,000 miles of transmission lines.

Regulatory Oversight

Progress Energy Carolinas, Inc. (PEC) and Progress Energy Florida, Inc. (PEF) have an obligation to provide reliable electric service at reasonable rates in a safe, environmentally responsible manner to their customers. Regulatory bodies in each of the states served by PEC and PEF oversee their decisions to construct new generation and transmission facilities as well as the rates, terms and conditions of their retail services. In addition, the Federal Energy Regulatory Commission (FERC) regulates wholesale electric rates and interstate transmission service.

The company's Regulatory Affairs staffs in the Carolinas and Florida work with the Florida Public Service Commission, the North Carolina Utilities Commission, the Public Service Commission of South Carolina and the FERC to obtain approval to implement new rates, tariffs and initiatives, including, but not limited to:

- Annual fuel costs
- Construction of new generation and/or transmission facilities
- Avoided cost rates
- Short- and long-term integrated resource plans
- Rates and tariffs
- Issuance of securities
- Contracts or transfer of assets to affiliated companies
- Efficiency and/or demand side management programs

In addition, PEC and PEF work with consumer advocates, including the Florida Office of Public Counsel, the North Carolina Utilities Commission Public Staff and the South Carolina Office of Regulatory Staff to ensure that customer interests are protected in regulatory actions.

Customer and Economic Growth

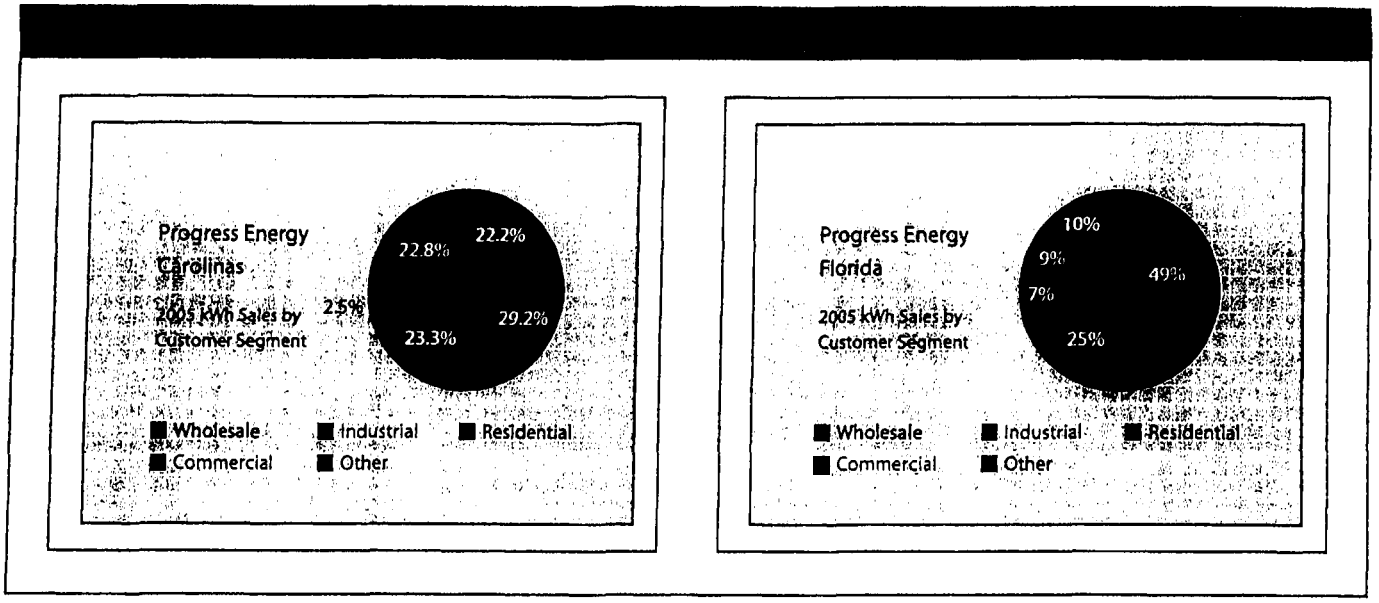
The United States is experiencing growing energy demand, even as the energy efficiency of our nation's economy continues to increase. U.S. energy demand is projected to grow at an average annual rate of 1.1 percent, while the energy efficiency of the economy is projected to grow at an average annual rate of 1.8 percent, according to the Energy Information Administration.

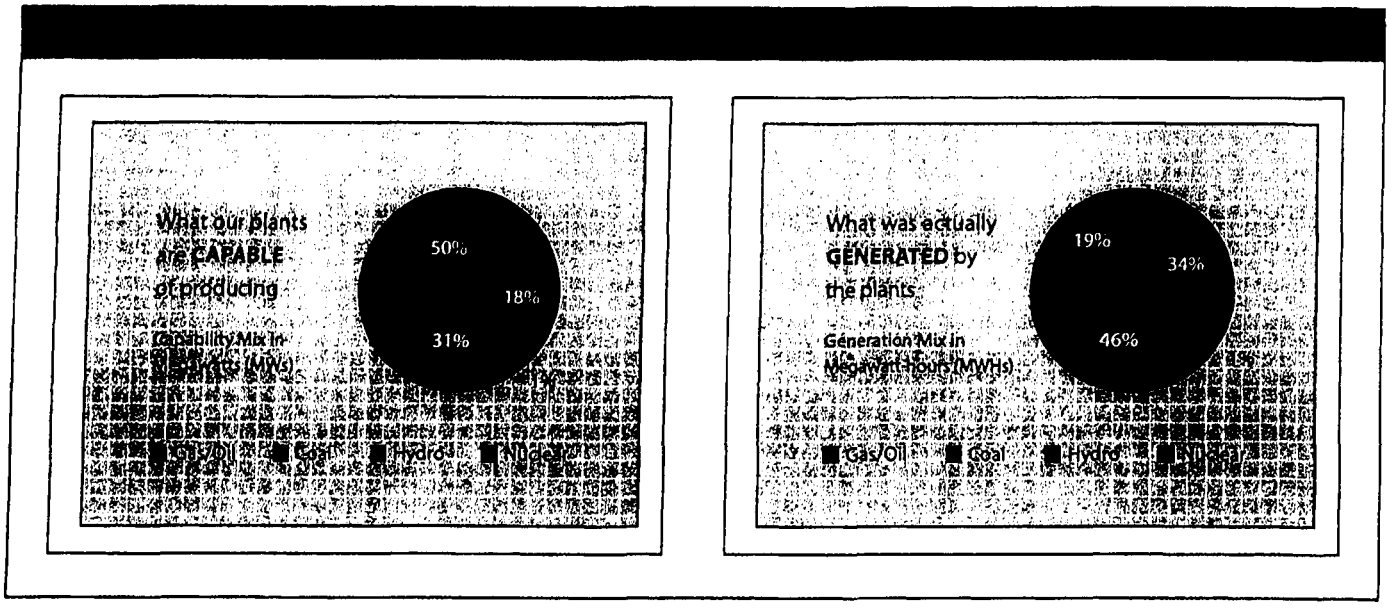
Between 2004 and 2005, the South had the largest numerical population growth (1.5 million) and the fastest rate of growth (1.4 percent) among all regions in the United States, according to the U.S. Census Bureau. Progress Energy has seen that growth rate firsthand in its service areas, particularly in North Carolina and Florida. Progress Energy Florida's five-year growth rate was 2.49 percent, and Progress Energy Carolinas' five-year growth rate was 2.2 percent through 2005. This economic growth is expected to continue in the company's service territory in the coming years.

Generation Mix and Locations

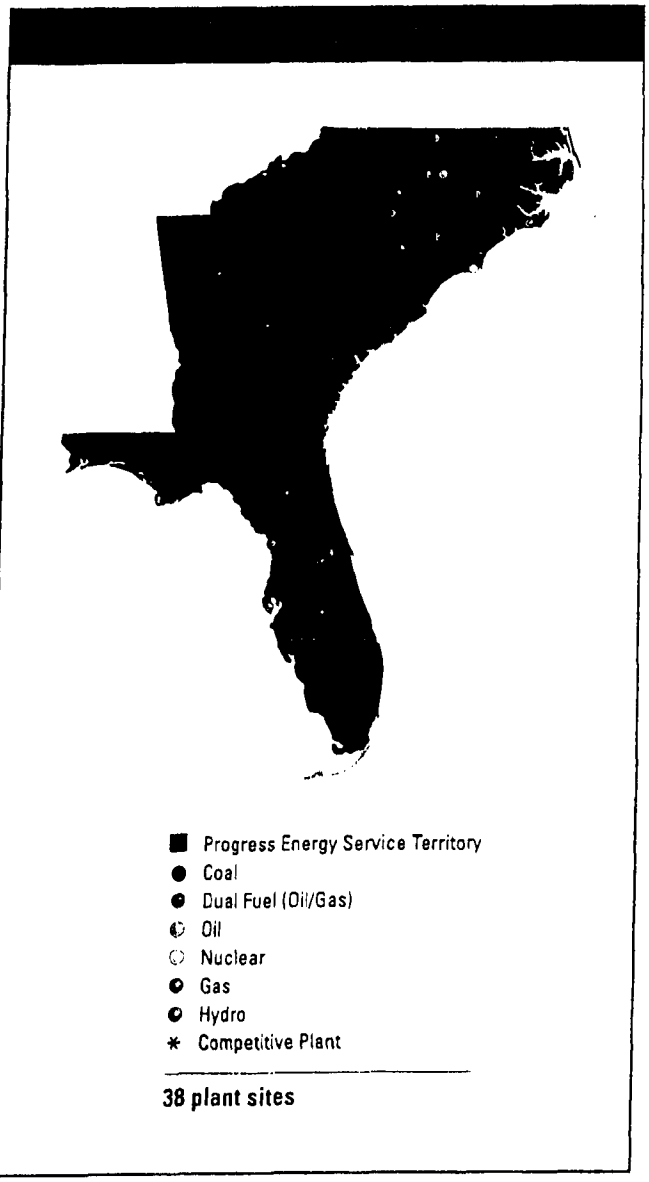
Progress Energy generates reliable, competitively priced energy from a diverse portfolio of fuel choices, including nuclear, coal, gas, oil and hydroelectric plants, at 38 sites in the Carolinas, Florida and Georgia.

070007-Hearing Exhibit 000400





070007-Hearing Exhibit 000401



Nonregulated Business

Competitive Commercial Operations

Competitive Commercial Operations is a business unit within Progress Ventures, the nonregulated subsidiary of Progress Energy, that manages long-term electric and gas contracts with other utilities, municipalities, marketing companies, and co-ops.

Progress Ventures has approximately 3,100 MW of competitive generation in Georgia, Florida and North Carolina at six facilities. All of the sites are strategically located near natural gas pipelines and power transmission corridors.

The competitive fleet is made up of:

- Monroe Plant, located in Monroe, Ga.
- Rowan County Plant, located near Salisbury, N.C.
- Effingham Plant, located northwest of Savannah, Ga.
- DeSoto Plant, located in DeSoto County, Fla.
- Walton County Plant, located in Monroe, Ga.
- Washington County Plant, located east of Macon, Ga.

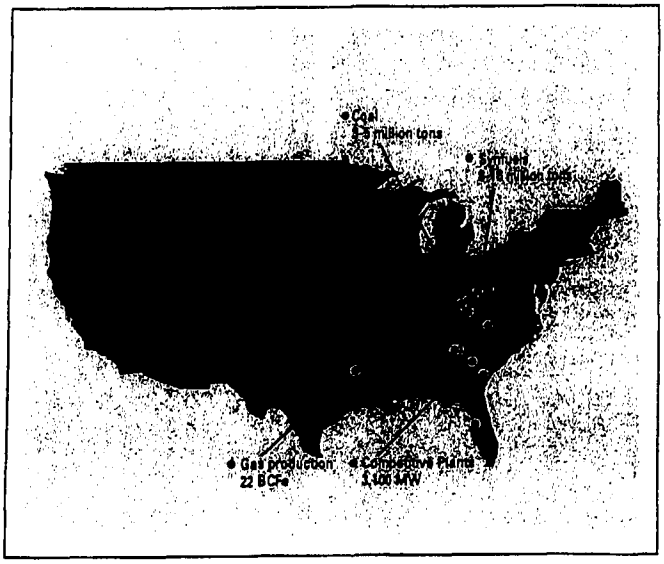
Natural Gas Production

Progress Ventures, through Progress Fuels, owns approximately 325 billion cubic feet equivalent (Bcfe) of proven natural gas and oil reserves in east Texas and Louisiana with annual net production of approximately 24.2 Bcfe. In 2004, Progress Fuels drilled 69 wells, all of which were economically viable.

River Terminals and Coal Facilities

Progress Ventures, through Progress Fuels, operates five river terminals located in Kentucky and West Virginia that are used for the storage, blending, and loading of coal, which is delivered by truck or railcar. These facilities are used by Progress Fuels to facilitate the transportation of coal.

Progress Fuels also has coal mining operations in Kentucky and southwest Virginia. Progress Fuels controls approximately 164 million tons of coal reserves and resources, approximately two-thirds of which are owned.



070007-Hearing Exhibit 000402

Synthetic Fuels

Florida Progress Corporation (FPC) became involved with the synthetic coal fuel business in 1998. Today, Progress Energy owns all of the interest in four entities, a majority interest in one entity, and a minority interest in another entity, which own facilities that produce synthetic fuel. These entities own a total of nine facilities in seven different locations in the Kentucky, West Virginia and Virginia coal-mining regions. Another three facilities are operated by Progress Fuels under contracts with third parties.

Synthetic fuel is formed by combining coal and coal fines with a chemical change agent. Formation of chemical bonds between the coal fines and the binding agent results in a chemical change in the product. The coal fines used in the process are recovered from coal sizing plants, plant refuse, waste coal from barge cleaning or river dredging operations. Independent laboratories certify the chemical change.

Synthetic fuel production that meets certain criteria allows companies to take tax credits that reduce their federal income taxes. The tax incentive is an outgrowth of energy legislation passed under the Carter Administration in the 1970s to encourage companies to find alternative fuel sources. Currently, the law authorizing these credits expires at the end of 2007, but it has been extended several times since its enactment in the 1970s.

In February 2005, Progress Energy announced that the Field Auditors of the Internal Revenue Service (IRS) verbally informed the company that the IRS National Office has concluded that the company's four Earthco synthetic fuel facilities met the placed-in-service requirement, which is one of the conditions to qualify for tax credits under Section 45K (formerly Section 29) of the Internal Revenue Code.

070007-Hearing Exhibit 000403

ENVIRONMENTAL MANAGEMENT
at Progress Energy

A commitment to excellence is an integral part of the company's culture, and this dedication extends to environmental performance.

Progress Energy's employees are focused on excellence in their environmental performance. A commitment to continuous improvement in environmental quality and stewardship – the cornerstone of Progress Energy's environmental vision – guides the company's actions, and benefits the company and the communities in which employees live and work.

The Environmental, Health & Safety Performance Council (EHSPC), which is made up of senior management, guides and directs corporate environmental policy. The council also monitors compliance and approves targets that measure, track and drive performance improvement. The board of directors' Operations, Environmental, Health and Safety Issues (OEHS) committee assesses these activities and makes recommendations to the board regarding these matters. While the company's business units assume responsibility for environmental compliance, a centralized, corporate environmental staff provides technical environmental support and leads implementation of environmental programs and activities.

Together, Progress Energy's environmental vision and policy set the expectation for excellence in environmental performance. The company's established environmental management systems (EMS) help manage the environmental aspects and impacts of its business and their associated business risks. Progress Energy's EMS generally follows the international ISO 14001 standard. EMS activities are coordinated through regular meetings of the company's environmental specialists.

Managing the environmental aspects and impacts of the company's business has been routine for many years. The formal EMS established a process for regular senior management review and revision of corporate policies and procedures, ensured that environmental performance is routinely assessed, and increased management confidence in the company's ability to identify and address environmental issues. While global climate change is a potentially significant environmental issue for the company, other key strategic issues that impact the company's approach are discussed in the next section.

Progress Energy, Inc. Environmental Policy

Environmental responsibility is a core value of Progress Energy. We are committed to excellence in our environmental practices and performance. We acknowledge our responsibility to be a good steward of the natural resources entrusted to our care while providing affordable and reliable energy to our customers. Environmental factors will be an integral part of planning, design, construction and operational decisions. Further, we will conduct business according to the following principles:

Compliance. Comply with local, state and federal environmental laws and regulations.

Performance Accountability. Maintain an environmental management system, including the use of objectives and goals to measure, track, drive and continually improve performance.

Minimizing Impacts. Effectively manage waste streams and promote prevention of pollution.

Take appropriate measures to prevent environmental degradation and be prepared to act effectively in the event of an environmental emergency.

Stewardship and Transparency. Proactively address environmental issues and find innovative solutions to protect and improve the environment.

Communicate environmental performance to stakeholders and support effective community efforts in environmental education, protection and conservation.

Management and Employee Commitment. Assure that employees and contractors are aware of their individual role in implementing this policy.

070007-Hearing Exhibit 000404

Key strategic issues

Progress Energy faces three key strategic issues in the coming years, each of which will play a role in the company's approach to climate change.

- Fuel price volatility
- Tightening clean air standards
- Need for new baseload generation

Fuel price volatility

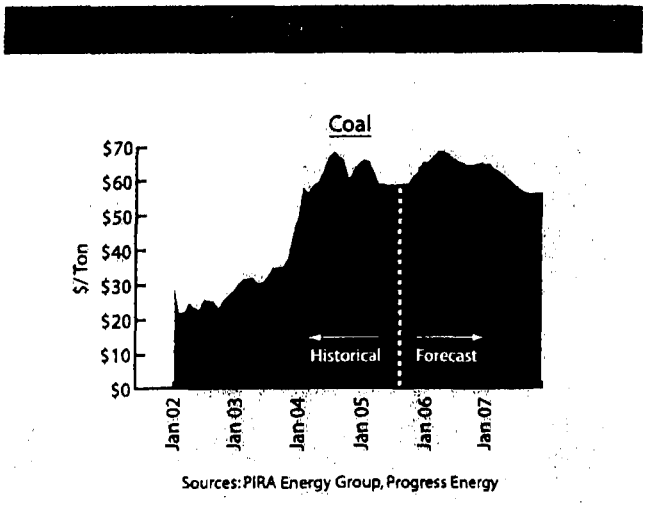
Progress Energy's priority is to provide energy that is reliable and affordable. The company generates electricity using coal, nuclear, natural gas, oil, and renewable sources, including hydroelectric. Thanks to this mix, the company is not overly dependent on a single source of energy.

High fossil fuel prices are impacting every aspect of the company's business. The company has a responsibility to manage these costs, and state regulatory commissions oversee and approve all changes to fuel costs.

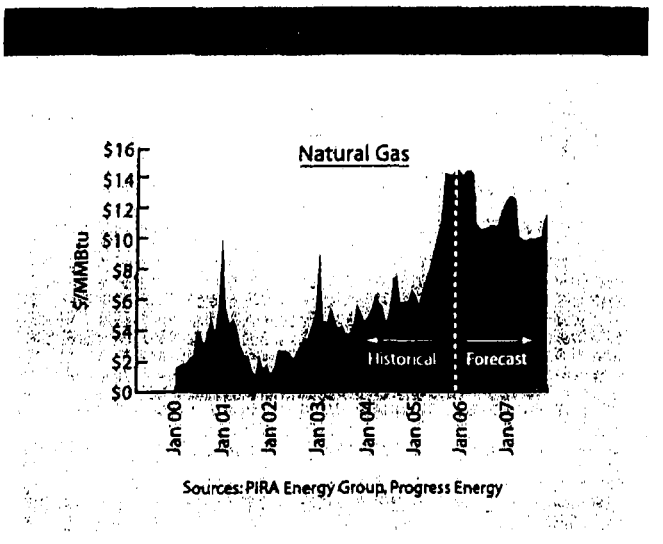
The most abundant, reliable and cost-effective fuel sources available to Progress Energy at this time are for coal and nuclear power generation. Using these sources helps to mitigate fuel cost impacts for customers and maintain fuel diversity.

Natural gas prices have seen tremendous price volatility over the past several years. In 2005, prices were double what they were two years before and almost triple what they were three years before. As a result of the continued natural gas price volatility in the market, Progress Energy is currently hedging a portion of its projected natural gas requirements. The hedging objectives are to reduce price volatility and to provide more certainty for customers.

The PIRA Energy Group, an international energy-consulting firm, expects oil prices to rise relative to natural gas over the long term. Oil's growth is concentrated in the transportation market where there are limited fuel alternatives. In the case of natural gas, the primary growth market is electric power generation, where other fuel alternatives exist.



Sources: PIRA Energy Group, Progress Energy



Sources: PIRA Energy Group, Progress Energy

The upside of gas prices will be limited by the need to remain competitive with coal in electric power generation. Moreover, the amount of liquified natural gas is expected to increase. Coal prices are expected to rise in the near term, but then remain flat for the long term, due to widely available supply and productivity improvements.

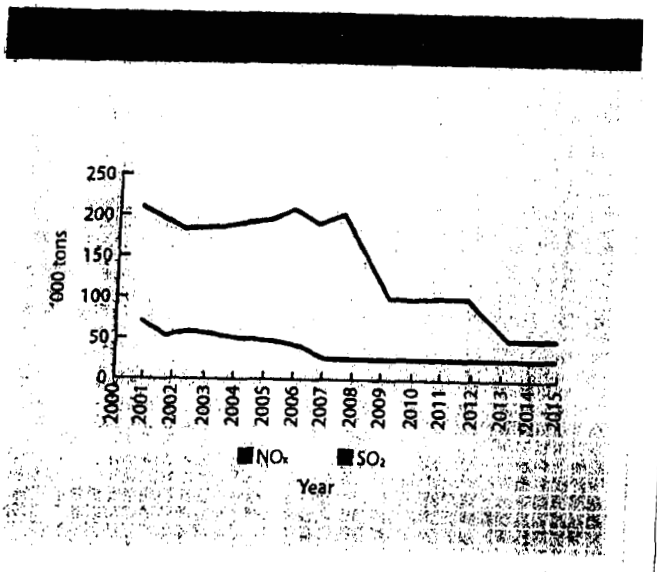
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070007-Hearing Exhibit 000406

Tightening clean air standards

Progress Energy has already taken steps to reduce air emissions at its plants in North Carolina as part of the state's Clean Smokestacks Act. Progress Energy joined a coalition of public officials, environmental organizations, citizen groups and businesses to support this law, which is a cost-effective plan to reduce emissions from the state's coal-fired power plants. This consensus-driven process has been viewed by other states as a positive example of collaborative environmental policymaking, and the U.S. Environmental Protection Agency recognized the group's efforts with a Clean Air Excellence Award in 2004.

The Clean Smokestacks Act requires significant reductions in sulfur dioxide (SO_2) and nitrogen oxides (NOx) emissions and sets hard caps for the companies to meet, meaning that no trading to meet the limits is allowed. By 2013, Progress Energy will cut SO_2 emissions by 74 percent and NOx emissions by 56 percent from 2001 levels in North Carolina. According to the N.C. Department of Environment and Natural Resources (DENR), the SO_2 and NOx control technologies installed statewide as part of Clean Smokestacks will also remove 65 percent of mercury emissions.



The chart shows actual and projected sulfur dioxide and nitrogen oxide reductions under the North Carolina Clean Smokestacks Act.

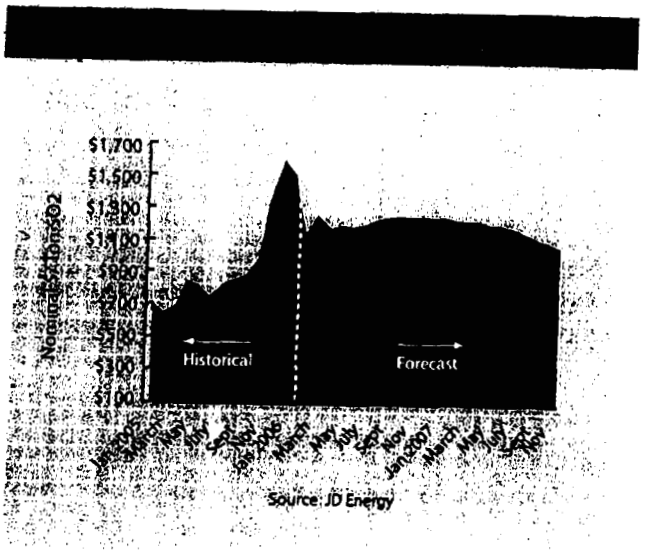
The company's first scrubber, which removes sulfur dioxide, began operating in November 2005 on Unit 1 at the Asheville Steam Electric Plant. Other SO_2 emissions reduction technologies will be installed at plants between 2006 and 2013. Progress Energy plans to install scrubbers at Asheville's Unit 2 and the Cape Fear, Mayo, Roxboro and Sutton plants and is installing NOx-reduction technologies at all of its coal-fired plants in the Carolinas.

Progress Energy projects that it will invest approximately $1.1 billion to $1.4 billion by the end of 2013 to meet the requirements of the Clean Smokestacks Act. These costs reflect the higher costs and quantities of construction materials, such as concrete and steel, refinement of cost and scope estimates for current projects, and increases in the estimated inflation factor applied to future project costs. The company is evaluating various design, technology and new generation options that could reduce these costs.

Clean Smokestacks, however, is just the beginning, and it has positioned Progress Energy to meet the more stringent requirements of the federal Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR) and Clean Air Visibility Rule (CAVR).

The federal Clean Air Interstate Rule requires significant reductions in emissions of SO_2 and NOx throughout the eastern United States, including Progress Energy's service areas in Florida and the Carolinas. At full implementation in 2015, CAIR would require a 70 percent cut in SO_2 emissions and a 65 percent reduction in NOx emissions from 2002 levels.

Under a cap-and-trade system like CAIR, utilities are given a limit on their emissions and are given the flexibility to trade allowances to help to meet that cap. For example, under the Clean Air Act Amendments of 1990, companies can trade SO_2 allowances, and one allowance is equal to one ton of SO_2. That program has resulted in significant SO_2 reductions.



The chart reflects SO_2 emissions allowance pricing from January 2005 projected through November 2007. Allowance prices significantly increased in 2005 to a new high of $1,600/ton.

Due to price volatility and uncertainty in SO_2 allowance prices in the future, the company has taken these risk factors into consideration as it develops its CAIR strategy.

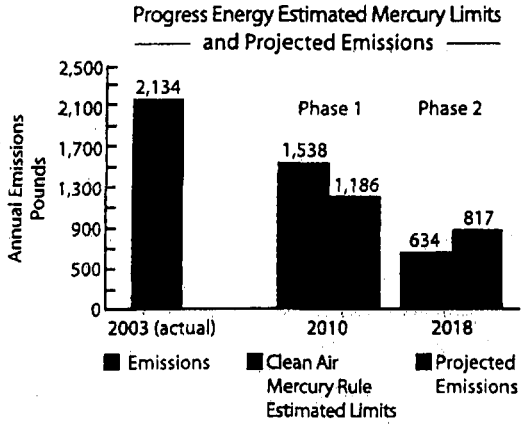
The federal Clean Air Mercury Rule requires significant reductions in mercury emissions. The Clean Air Mercury Rule also sets up a trading program and sets two deadlines for compliance – the first in 2010 and the second in 2018. This trading program is particularly important because it is not known if technologies will be commercially available in time to meet emissions caps in 2018.

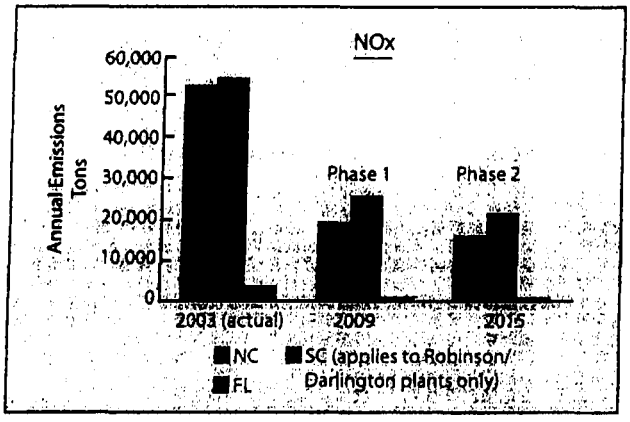
In June 2005, the U.S. Environmental Protection Agency issued the Clean Air Visibility Rule (CAVR). The rule requires states to identify facilities, including power plants, which began operation between August 1962 and August 1977 with the potential to produce emissions that affect visibility in specially protected areas. To help restore visibility in those areas, states must require the facilities to install Best Available Retrofit Technology (BART) to control their emissions.

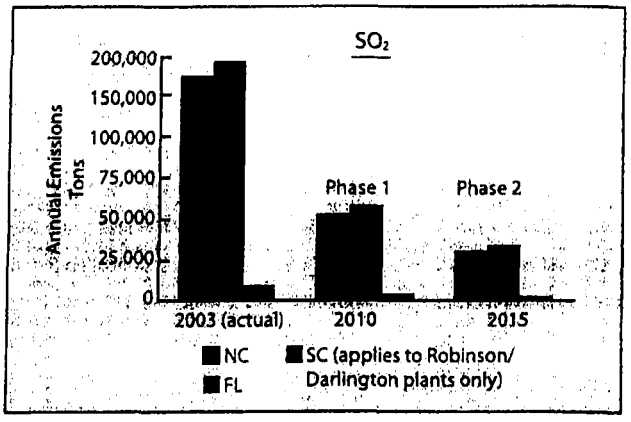
Progress Energy expects to meet the first phase caps under the Clean Air Mercury Rule, due to air quality work already completed under CAIR and the N.C. Clean Smokestacks Act. New technology will need to be commercially available and trading allowed in order for the company to meet the Phase 2 caps in 2018.

Depending on the approach taken by the states, the reductions associated with BART would begin to take effect in 2014. CAVR included EPA's determination that compliance with the NOx and SO_2 requirements of CAIR may be used by states as a BART substitute.

In Florida and the Carolinas, Progress Energy is finalizing compliance plans for the Clean Air Interstate Rule and the Clean Air Mercury Rule. Progress Energy expects that its plans to comply with CAIR and CAMR will fulfill BART obligations under CAVR.







North Carolina	55,054	25,266	21,521
Florida	53,264	19,277	16,064
South Carolina	3,500	894	745

North Carolina	196,253	64,025	44,773
Florida	174,773	57,951	40,525
South Carolina	9,757	1,454	1,017

The charts above outline the schedules and estimated limits Progress Energy will need to meet to comply with the Clean Air Interstate Rule.

070007-Hearing Exhibit 000407

In Florida, the focus of the effort will be at the Crystal River Plant, the largest coal-fired plant in Florida, although the air quality near the Crystal River Plant and in all of Florida meets the standards set by the EPA and the state of Florida for the protection of public health. Florida is one of only three states east of the Mississippi River that meet all of the standards.

In addition, as part of the process of operating scrubbers and selective catalytic reduction units (SCRs), which will likely be installed to meet the requirements of CAIR, Progress Energy will be purchasing large amounts of reagents, such as limestone and urea. These products are needed to significantly reduce SO_2 and NOx emissions.

Need for new baseload generation

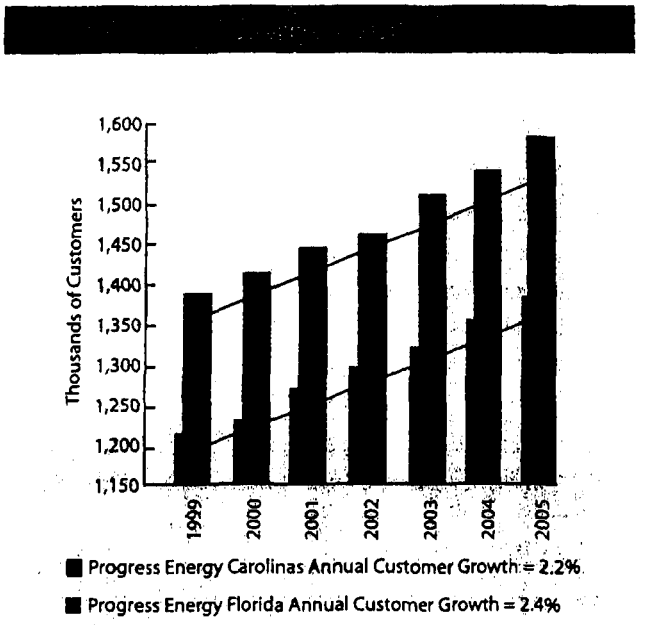
The third key strategic issue facing Progress Energy is customer and demand growth; and how we address that issue with new baseload generation.

Progress Energy is very fortunate to operate in a growing region. Both Progress Energy Carolinas and Progress Energy Florida are adding about 60,000-70,000 customers per year. That growth trajectory is projected to continue as people keep migrating to the southeastern United States, and as people consume more electricity, live in larger homes and rely increasingly on technology and electronics in their everyday lives. Meeting this growing demand for power will require a balanced solution.

Progress Energy's customer and demand growth is driving the company's need for large baseload generation. Since Progress Energy Carolinas and Progress Energy Florida last added baseload generation in the mid-1980s, the utilities have grown by 1 million total customers.

In North Carolina, Progress Energy's last baseload plant was the Harris Nuclear Plant, which was brought online in 1987. In Florida, the most recent baseload plant was the last coal-fired unit at the Crystal River Plant, completed in 1984.

In the interim, the company has focused on building plants that serve intermediate and peak loads, meaning that they do not run all the time as baseload plants do. The company has six combined-cycle plants, providing a total of 2,707 MW of generating capacity. A combined-cycle unit consists of two combustion turbine (CT) generators and a system for recovering exhaust heat from the CTs to produce steam, which generates more electricity by sending the steam through a turbine. For the same amount of fuel, the combined-cycle plant generates about 50 percent more electricity, making it highly efficient.



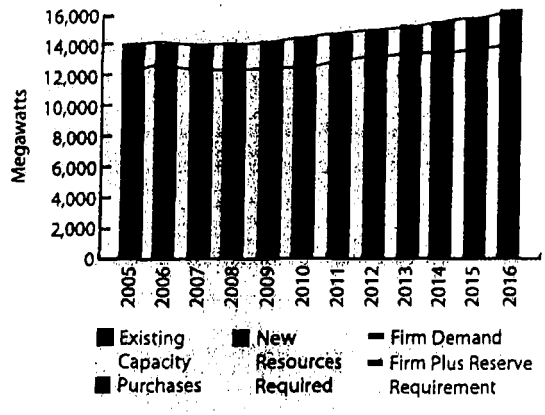
The largest of these plants is the Hines Energy Complex, which is located near the town of Bartow, Fla., and is capable of producing 1,514 MW of electricity. The first combined-cycle unit at Hines began commercial operation in 1999, followed by a second unit in 2003 and a third unit in 2005. The company broke ground on the fourth unit in February 2006.

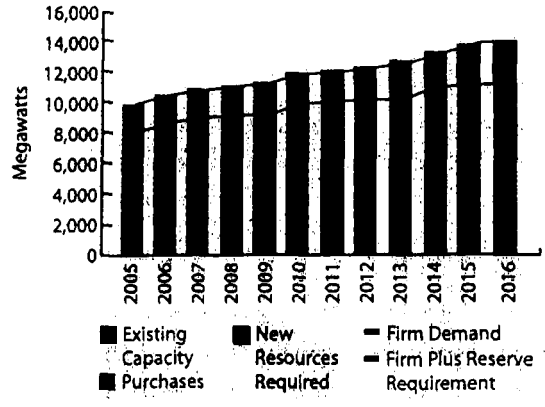
The company also has 103 combustion turbine (CT) units, with a combined generation capacity of 7,748 MW. CTs, which are similar to jet engines, can reach full power quickly, which enables the company to respond to peak demands. The Wayne County Plant in Goldsboro, N.C., is one example of a combustion turbine facility. The plant began operating in 2000 and has four combustion turbine units, capable of producing 668 MW of electricity.

In addition to building plants to serve intermediate and peak demands, Progress Energy has also instituted conservation and efficiency programs to help customers reduce their energy usage and to address growing demand. For example, since 1981, the company's energy-efficiency programs have reduced usage by more than 26 billion kWh.

As the forecast charts on page 10 show, new resources will be required beginning as soon as 2009 in the Carolinas and 2010 in Florida. The company also purchases power through contracts with other utilities and on the wholesale market to help make up the difference between

070007-Hearing Exhibit 000408





capacity and firm demand, and to help meet reserve requirements set forth by state utility regulators.

Firm demand is the sum of total retail and wholesale demand, plus losses, less the impact of interruptible loads. In the Carolinas, the company's reserve requirement is 12 percent to 15 percent above firm demand. In Florida, the reserve requirement is 20 percent, as set forward in an agreement with the Florida Public Service Commission.

However, there is uncertainty about the availability of purchased power and the volatility of the wholesale electricity markets. Because the company has an obligation to provide affordable, reliable electricity in a safe, environmentally sound way, as well as an obligation to meet its reserve requirements, relying on purchasing power to meet forecasted growth is not a viable option.

To ensure power for the future, the company plans ahead 10 years or more. This planning shows that hundreds of thousands more customers will be depending on Progress Energy to provide reliable electricity. Based on these growth expectations, Progress Energy will require new baseload generation in both Florida and the Carolinas in the middle of the next decade.

As the company approaches this new era of large plant construction, it is evaluating all of the best available options, including advanced-design nuclear and clean coal technologies, which are the most cost-effective and environmentally friendly forms of generation that can address the projected growth.

The company informed the Nuclear Regulatory Commission in August 2005 that it plans to submit a combined license application for a new nuclear plant. It updated those plans in November 2005 to include a second combined license – one for the Carolinas and one for Florida. Each application covers up to two reactors at each site. The licensing process, once completed, gives the permit holder the option to construct and operate units on a specific site – it does not obligate the company to build.

In January 2006, the company announced that it would evaluate the Harris Nuclear Plant site near New Hill, N.C., for possible future nuclear generation expansion. Progress Energy chose the Harris site, after evaluating several sites in the Carolinas, based on its available land, transmission lines and proximity to cooling water and to Progress Energy Carolinas' largest area of customer concentration. The company expects to select a site in Florida in the first part of 2006.

A final decision to build another nuclear plant is still several years away. It will be based on many factors, including public and political support, regulatory approval and forecasts for energy demand and economic conditions later this decade. In order to provide the most reliable, safe and efficient mix of energy resources for its customers, Progress Energy is taking steps now to keep the option for nuclear open and viable in the future.

070007-Hearing Exhibit 000409

Global climate change position

Progress Energy recognizes the importance of the global climate change issue and the enormous scale and complexity of the problem. Even with the considerable scientific uncertainties and the need for much more research, we believe there is sufficient understanding of the problem and its potential consequences to warrant prudent action by both the private and public sectors.

We are actively learning about the rapidly evolving science of global climate change. Our discussions with outside experts have clarified key facts about the issue, including the extent to which the concentration of carbon dioxide in the atmosphere is increasing. Scientific models vary widely in their projections of the rate of climate change and the ecological effects of the temperature increases.

Nonetheless, evidence shows that the climate is changing and that humans are partly responsible. Furthermore, it has become clear to us that even stabilizing carbon dioxide concentrations in the atmosphere will require a major technological revolution and a long-term sustained focus at the international, national and state levels.

While the solutions should be economywide, we are already taking a number of steps in our operations and with our customers to increase efficiencies and avoid or reduce carbon dioxide emissions. We are evaluating a balanced range of future options we think are realistic in our region of the country, including expanded efficiency programs and new energy-production sources, ranging from renewable energy to advanced nuclear, gas and clean coal technologies.

No silver bullet technological fix currently exists for reducing greenhouse gas emissions, which means that transitional technologies and long-term solutions will be required. Progress Energy is committed to developing consensus-based strategies with policymakers and stakeholders in our region, which faces continued growth in its population, economic activity and energy needs.

Key Points of Progress Energy's Position on Global Climate Change

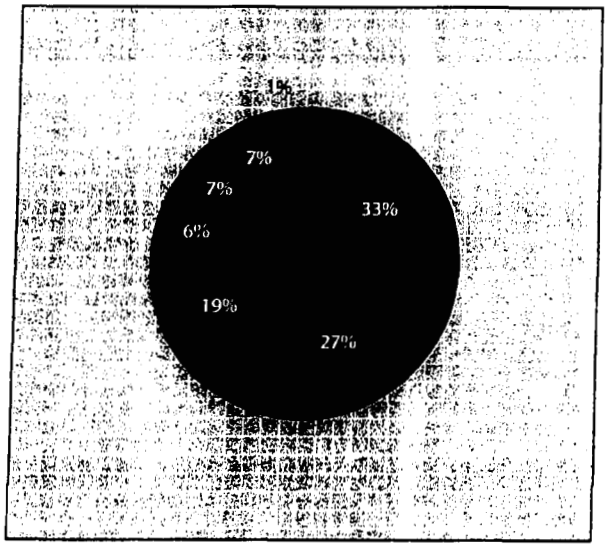
Policies to address global climate change present business risk to Progress Energy and social, economic and environmental risks to the areas we serve. Even with the considerable scientific uncertainties about this issue, we believe there is sufficient understanding to warrant action by both the private and public sectors. While continuing to fulfill our obligation to provide reliable, affordable electric service to our customers, we are taking action on this important issue as part of our strong commitment to environmental stewardship and responsible corporate citizenship.

Progress Energy believes in the following principles:

- Climate change policies should be comprehensive in that they include all sectors of the economy, cost effective in that they are supported by rigorous economic analysis, and achievable in that the goals and schedule are realistic.
- Climate change policies should be designed to promote substantial technological innovation on multiple fronts and timely, cost-effective deployment of technologies.
- Climate change policies should not harm the economy or our ability to provide reliable, affordable electric service to our customers.
- Climate change policies should promote fuel diversity by encouraging renewable energy, advanced nuclear, gas and clean coal technologies.
- The global nature of climate change requires a national policy framework, informed by international developments and commitments.
- The country's regional differences require flexibility in the implementation of policy solutions.
- While participating in the national policy debate, we will work with stakeholders in our region to develop consensus-based strategies to address climate change and help our region succeed as future national policies are implemented.

Any proposals to establish a national climate change policy should be evaluated based on how well they address these climate change principles.

070007-Hearing Exhibit 000410



- Electricity Generation
- Transportation
- Industrial
- Residential
- Agriculture
- Commercial
- U.S. Territories

Measured in teragrams of CO_2 equivalent (Tg CO_2 Eq.)

This chart from the U.S. Environmental Protection Agency shows that a variety of economic sectors contribute to greenhouse gas emissions in the United States. Progress Energy believes that climate change policies should be comprehensive and include all sectors of the economy.

Source: U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003.*

070007-Hearing Exhibit 000411

INVENTORY OF COMPANY activities and research

While Progress Energy will address the risks associated with global climate change on its business in the coming years, the company is already taking actions to mitigate that risk, including nuclear uprates, fossil plant optimization projects, energy-efficiency programs, renewable and alternative energy development and research, and other carbon dioxide- reduction efforts.

Nuclear Uprates and Expansion

Since 2001, Progress Energy has completed power uprates totaling approximately 315 MW at its nuclear plants in the Carolinas and Florida, resulting in more than 36 million tons of CO_2 avoided. A power uprate increases the maximum power level at which a nuclear plant may operate. This incremental MW increase from uprates helped avoid building or purchasing additional power from fossil plants, which would have resulted in increased CO_2 emissions.

In 2005, Progress Energy notified the U.S. Nuclear Regulatory Commission (NRC) that it will file two combined license applications for possible new nuclear units. The company intends to file one application for the Carolinas and one for Florida. The notice is not a commitment to build a nuclear plant in either or both locations, but it is a necessary step to keep open the option of building nuclear plants to meet the growing electricity needs and demands of the company's customers.

The company expects to submit applications for both combined licenses to the NRC by 2008. If the company moves forward and gains license approval, construction could begin as early as 2010, with plants coming online around 2016.

Pursuing the licensing process provides the company the opportunity to maintain a diverse fuel mix in meeting future demand for power. Variables including power market conditions, projections in the area of the proposed plant, fuel prices, the regulatory environment and the ability to obtain financing will impact the company's decision regarding which future generation sources to pursue.

Fossil Plant Optimization Projects

In addition to nuclear plant uprates, Progress Energy has undertaken combustion optimization projects to improve efficiency at its fossil plants, including the Mayo Plant in Person County, N.C., and the Sutton Plant in Wilmington, N.C. By undertaking these projects at the Sutton Plant, for example, nitrogen oxide emissions were reduced by more than 25 percent and the plant improved combustion efficiency by 40 percent. This optimization program is being expanded to include all coal-fired sites.

The company installed its first scrubber, which removes sulfur dioxide, at the Asheville Plant in November 2005. In addition, the company has installed selective catalytic reduction units (SCRs), which remove nitrogen oxides, on five units in North Carolina. The company plans to install additional SCRs and scrubbers and other emissions-reducing technologies at its plants in the coming years.

Energy-Efficiency Programs

To help consumers use energy more wisely, Progress Energy has robust energy-efficiency programs in the Carolinas and Florida, and an aggressive demand side management (DSM) program in Florida, which began in 1981. In addition, Progress Energy Carolinas began its energy efficiency programs in the 1970s, with demand side management in the 1980s and 1990s.

The company offers energy-efficiency and DSM programs for both residential and business customers. Since 1981, energy-efficiency programs have reduced usage by more than 26 billion kWh in the Carolinas and Florida. In addition, these energy-efficiency and conservation programs have helped the company avoid 6.24 million tons of carbon dioxide emissions in Florida and 9.92 million tons in the Carolinas.

Residential

- Home Energy Check: Progress Energy's Home Energy Check is a comprehensive residential energy-evaluation program designed to help customers identify the best ways to save energy in their homes and find the resources to make the savings happen. The program

070007-Hearing Exhibit 000412

provides customers with an analysis of energy consumption and recommendations on energy efficiency improvements. The Home Energy Check helps customers identify and evaluate cost-effective energy-saving measures for their homes.

The company also offers an online home energy check, which enables customers to quickly answer common questions regarding energy usage and provides a full range of personalized recommendations for managing home energy costs. Customers receive specific recommendations for their households with detailed approaches for better managing energy use and saving money. The analysis also includes an automatic download of the customer's actual electric bill history.

- **Home Energy Improvement:** Home Energy Improvement combines thermal envelope efficiency improvements with upgraded equipment and appliances in existing homes.

- **Attic Insulation Upgrade:** This program encourages customers who have electric space heat to add ceiling insulation. Progress Energy pays a portion of the installed cost.

- **Duct Test and Repair:** This program helps identify and reduce energy loss by measuring air leakage rate through the central duct system. A customer must have an electric heating and centrally ducted cooling system to participate. Progress Energy pays for a portion of the test and repair.

- **High-Efficiency Electric Heat Pumps:** This program pays a financial incentive to replace existing electric heating equipment with high-efficiency electric heat pumps. The specific incentive is based on minimum heating and/or cooling efficiency levels. The indoor air handler and outdoor condenser must both be replaced with new equipment to qualify for this rebate.

- **Residential New Construction (Home Advantage):** The Home Advantage Program promotes energy-efficient construction that exceeds the building code. Information, education and consultation are provided to home builders and contractors on energy-related issues and efficiency measures. Mastic sealant on the home's duct system and energy-efficient electric heat pumps are required for participation.

- **Energy-Efficient Home Program:** Energy-Efficient Homes are certified to meet the standards of the U.S. Environmental Protection Agency's Energy Star® program. Annual energy costs may be reduced up to 30 percent due to high-efficiency heating and cooling equipment and high-quality materials and construction. Energy-Efficient Homes qualify for Progress Energy's energy-conservation discount on monthly electric bills.

- **Energy Efficiency Financing:** This program connects customers with screened contractors who provide complete installation and financing on a range of energy-saving home improvements. The financing may be used to make improvements that enable the home to meet the Energy Star criteria and qualify for Progress Energy's energy-conservation discount on monthly electric bills.

- **Time-of-Use Rates:** Progress Energy Carolinas offers time-of-use (TOU) rates to its customers. These rates provide incentives for customers to shift consumption of electricity to lower-cost off-peak periods and lower their electric bill.

- **5 Percent Energy Conservation Discount:** Customers whose homes meet the Energy Star criteria qualify for a 5 percent discount on their monthly electric bill. Progress Energy offers related programs to encourage and assist customers in meeting the Energy Star energy-efficiency requirements.

- **Low Income Weatherization Assistance (LIWAP):** An umbrella program improves the energy efficiency of low-income family homes. Efficiency measures and incentives are identical to those offered in Progress Energy Florida's Home Energy Improvement Program.

- **Residential Energy Management:** This voluntary load control program reduces winter peak demand in Florida by interrupting electric service to water heaters and central electric heating units. The monthly bill credit is paid during winter months (November-March) when customer usage exceeds 600 kWh per month.

- **Online Account Access:** Energy analysis graphs allow customers to compare their electricity usage in the current and previous year

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to the average temperature by month; compare past 12 months' electricity usage to the high, low and average temperature for the same period; and compare average monthly temperatures for the past 24 months. The energy analysis details allow customers to view their past 24 months of electricity usage, including date the bill was mailed; number of days in billing cycle; kWh (kilowatt-hour) usage per month; daily kWh usage; average, low and high temperature for the month; and daily temperature information for the month. These tools assist customers with understanding their energy usage patterns and identifying opportunities to reduce energy consumption.

- **"Lower My Bill" Toolkit:** This tool provides online tips and specific steps to help customers determine actions to reduce energy consumption and lower utility bills. The suggestions range from relatively simple no-cost steps to more extensive actions involving insulation and heating and cooling equipment. Information on payment options is included.

- **Energy Saving Tips:** Progress Energy provides online tips on how to reduce home energy costs, including information on the typical biggest household energy wasters and how a few simple actions can increase efficiency. Topics include energy-efficient heat pumps, mold, insulation R-values, air conditioning, appliances and pools, attics and roofing, building/additions, ceiling fans, ducts, fireplaces, heating, hot water, humidistats, landscaping, seasonal tips, solar film and thermostats.

Commercial

- **Business Energy Check:** A company representative surveys a facility and makes recommendations on low-cost or no-cost energy-saving practices and measures. Business energy check types include free walk-through, customer-completed (online) and paid energy analysis.

- **Better Business:** An umbrella efficiency program for existing commercial and industrial buildings, this program provides customers information and advice on energy-related issues and efficiency measures. Promotes the following energy-efficiency measures:

  - **HVAC Equipment:** A financial incentive is paid per kW reduced for the purchase of high-efficiency HVAC equipment such as packaged terminal heat pumps, packaged rooftop units, water-cooled and air-cooled chillers and unitary heat pumps and air conditioners.

  - **Energy Recovery Ventilation:** This program offers a financial incentive for the installation of high-efficiency energy- recovery ventilation units that remove heat and humidity from conditioned space.

  - **Duct Leakage Test and Repair:** This program helps identify and reduce energy loss by measuring air leakage rate through the central duct system. Progress Energy Florida pays for a portion of the test and repair.

  - **Ceiling Insulation Upgrade:** This program encourages customers who have electric space heat to add ceiling insulation. Progress Energy pays a portion of the installed cost.

  - **Cool Roof:** This initiative promotes the installation of "cool roof" coating that reflects heat and sun. The customer must have an electric cooling system to participate. Progress Energy Florida pays a portion of the installed cost.

- **Energy Resource Center:** Progress Energy offers its large commercial, industrial and government customers a wide array of tools and resources these customers can use to manage their energy usage and to reduce their electrical demand and overall energy costs. Through the Energy Resource Center located on the Progress Energy Web site, Progress Energy provides newsletters, online tools and information which cover energy-efficiency topics such as:

  - Electric chiller operation
  - Lighting system efficiency
  - Compressed air systems
  - Motor management
  - Variable speed drives
  - How to conduct an energy audit

Also located on the Energy Resource Center Web site is Progress Energy's Energy Profiler Online tool. Through this service, customers can analyze their electrical usage to gain an in-depth understanding of when and how they are using electrical energy. These data are essential for identifying potential energy savings opportunities.

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- **Commercial/Industrial New Construction:** An umbrella efficiency program for new commercial and industrial buildings, this program provides information, education and advice on energy-related issues and efficiency measures by involvement early in the building's design process. The program also provides incentives for energy-efficient equipment, such as HVAC equipment, energy-recovery ventilation and cool roof coating. Incentive levels are identical to those offered in the Better Business program for existing buildings.

- **Innovation Incentive:** This program provides incentives for customer-specific demand and energy-conservation projects, on a case-by-case basis. To be eligible, projects must reduce or shift a minimum of 10 kW of peak demand.

- **Standby Generation:** This is a voluntary demand control program available to all commercial/industrial customers in Florida with on-site generation capability. The customer controls the equipment but operates it when needed by Progress Energy Florida.

- **Interruptible Service:** Progress Energy Florida interrupts service by disconnecting electric service at the breaker during peak or emergency conditions. This service is available to any nonresidential customer with an average billing demand of at least 500 kW. A monthly credit is paid based on level of billing demand and load factor.

- **Curtailable Service:** This service is similar to interruptible service, but the customer's entire load is not shed. This program is available to any nonresidential customer with an average billing demand of at least 500 kW. The customer must be willing to reduce 25 percent of the average monthly billing demand upon request. A monthly credit is paid to customer based on level of curtailable demand.

- **CIG Account Management:** All Progress Energy commercial, industrial and government customers with an electrical demand greater than 200 kW are assigned to a Progress Energy account executive (AE). The AEs work hand in hand with their assigned customers to help them manage their energy usage and costs and to assist them in developing energy-efficiency solutions. The AEs go onsite with the customer to better understand their customer's business operation and energy needs.

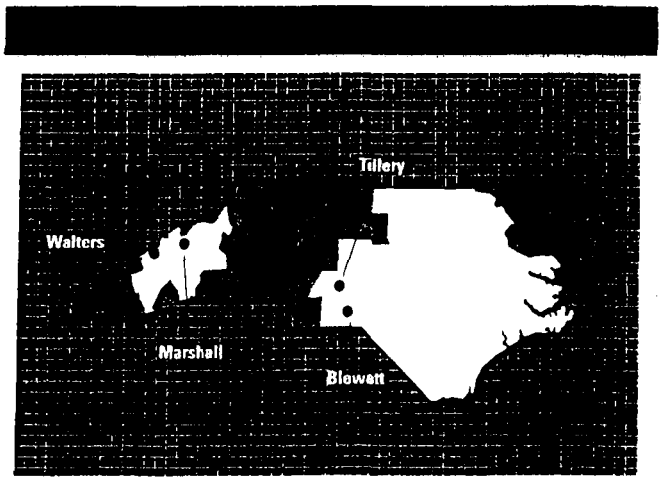
Progress Energy is committed to implementing efficiency programs for its customers. As these programs continue to mature and become more cost effective, the company will work closely with its state regulators to design and update these programs throughout its service territory.

Renewable and Alternative Energy Development and Research

Hydroelectric Plants

Progress Energy has four hydroelectric plants in North Carolina, capable of producing 218 MW of electricity. In November 2005, Progress Energy submitted a draft license renewal application to relicense the Tillery and Blewett plants.

- **Blewett:** The six-unit, 22 MW Blewett Hydroelectric Plant is located near Lilesville, N.C. The site also includes four combustion turbine units.
- **Marshall:** The two-unit, 5 MW Marshall Hydroelectric Plant is located near Marshall, N.C.
- **Tillery:** The four-unit, 86 MW Tillery Hydroelectric Plant is located near Mt. Gilead, N.C.
- **Walters:** The three-unit, 105 MW Walters Hydroelectric Plant is located near Waterville, N.C.



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Solar Programs

Photovoltaic systems (PV) convert sunlight directly into electricity. Commonly known as "solar cells," these systems already power more than 1 billion handheld calculators, as well as millions of watches, portable lights and battery chargers. Larger, more complex systems provide electricity to pump water, power communications equipment, light homes and operate appliances. Progress Energy has projects or future initiatives representing more than 330 kW and 440,000 kWh of PV generation throughout Progress Energy's service area, including:

- **Manufactured Housing Photovoltaic Pilot Project:** Generating 8 kW capacity or 11,680 kWh of energy per year, this project was nationally recognized with the Interstate Renewable Energy Council's 2002 Innovation Award. This project also received the 2003 Florida Sustainable Energy Award. Progress Energy teamed up with the Florida Solar Energy Center, an institute of the University of Central Florida, and Palm Harbor Homes, one of the largest producers of manufactured homes in the United States, to install PV systems on six Palm Harbor Homes. Compared with the time associated with typical PV installation on a manufactured home, which is three to four days, the project team was able to reduce the installation time to one to two days because of the efficiencies gained in the factory setting.

- **BP Partnership:** BP has worked with Progress Energy to interconnect 17 stores with gas pump canopies fitted with power-generating PV systems throughout the Orlando area. Progress Energy partners with BP to monitor and evaluate the PV production from a sampling of the sites.

- **Econolochatchee Photovoltaic Array:** The Econolochatchee Photovoltaic Array was originally commissioned in August 1988 at the Econolochatchee substation in Orlando, Fla. The PV system was designed to research power generating technologies that could generate electric power that would then be delivered directly into the electric grid.

- **The Nature Conservancy at the Disney Wilderness Preserve:** The Nature Conservancy at the Disney Wilderness Preserve features two grid-connected PV systems. The two 6.5-kW systems were installed to promote renewable energy technologies at the Disney Nature Conservancy learning center located in Kissimmee, Fla. The buildings were officially opened to the public in October 1999.

- **SunSmart School Program:** Progress Energy partnered with the Florida Department of Environmental Protection (FDEP) and the Florida Solar Energy Center (FSEC) to demonstrate PV systems at five schools throughout the company's service territory. This demonstration is part of the SunSmart Schools program, which is a collaborative initiative that provides students with interactive learning opportunities to explore alternative energy sources. The five-year project was launched in 2003 with the installation of 4-kW PV systems at five schools. Students can track energy production from the PV system mounted on a school's roof, even if they do not attend that school. Students work within their individual classrooms to conduct scientific experiments and mathematical computations based upon the PV system's energy production.

- **The Solar Energy Education Program:** The Solar Energy Education program was implemented in 2001, and it is estimated that this initiative benefited 7,500 students, and equipped 30 schools with solar energy education kits, curriculum materials, and an interactive, energy-focused Web site.

- **Additional Customer-Owned and Operated Interconnected PV Systems:** Progress Energy has worked with several residential/commercial customers to interconnect PV systems to its electrical grid.

Hydrogen and Fuel Cell Projects

Hydrogen is the third most abundant element on earth and can be extracted from many sources, including biomass, water or natural gas. Hydrogen, therefore, is a renewable or sustainable energy carrier and will never run out. The challenge is developing an economical way to extract hydrogen to justify replacing existing fuels. Progress Energy is investing in fuel cell companies and participating in many research and pilot projects to test the feasibility of this fuel source for future electric generation.

- **Fuel cell investment:** In December 2005, Progress Energy announced a commitment of $1 million to Microcell Corp., a Raleigh, N.C.-based company working to bring commercially available fuel cell applications to industrial, commercial and consumer markets.

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Fuel cells are electrochemical devices that convert chemical energy directly into electrical energy. Unlike batteries, which convert chemical energy stored within the battery, fuel cells theoretically continue to deliver electrical energy as long as fuel is supplied. The Microcell fuel cell is a proton-exchange membrane (PEM) converted to the form of a microfiber. It differs from other fuel-cell designs (in that all the fuel cell components are extruded into a single microfiber) and shows promise for its potential to be mass-produced more efficiently than other designs.

One potential application for fuel cells is in operating distributed generation, or power plants located on or near a customer's property. While any widespread consumer application of fuel cell technology is likely years away, increased research and development – and active pilots and demonstrations – help to accelerate the process. Progress Energy will remain active in this research and development.

- **Homosassa Springs State Wildlife Park – demonstration hydrogen production and fuel cell project:** Progress Energy and the FDEP have teamed up to develop a sustainable hydrogen generator and fuel cell for the wildlife park in Citrus County, Fla. The hydrogen fuel cell and 5-kW PV system demonstrates sustainable energy, requiring only sunlight and water as a fuel source. The PV cells convert sunlight into electricity, which operates an electrolyzer to produce hydrogen and oxygen from water. The oxygen is released harmlessly into the atmosphere, while the hydrogen is used inside a fuel cell, which is similar to a battery, to generate electricity for the park's Wildlife Encounter Pavilion.

- **Hydrogen fuel cell vehicles and hydrogen production:** Progress Energy is piloting fuel cell vehicles, also known as FCVs, and will use hydrogen-fueled Ford Focus FCVs in Florida. The vehicles are driven by energy counselors who make home visits to advise customers in energy-efficiency methods. Progress Energy and the FDEP have created the first hydrogen car support facility in central Florida. Ford Motor Company has delivered five hydrogen vehicles for a three-year field test. The hydrogen fueling station is currently under construction at the Progress Energy's Jamestown Operations Center in Oviedo, Fla. The partnership is between Progress Energy, FDEP, Ford and BP.

- **Hydrogen ICE buses and hydrogen fueling station:** Progress Energy, the FDEP and Chevron have teamed up for this hydrogen fueling station to be located on property owned by Progress Energy near the Orlando International Airport. The station is intended to fuel eight state-owned Ford V-10, E-450 hydrogen-powered shuttle buses transporting visitors. With a range of up to 150 miles and near-zero emissions, including carbon dioxide, the Ford hydrogen shuttle bus uses an internal combustion engine designed to run on hydrogen fuel instead of gasoline. The station will provide a test platform for showcasing the safe and cost-effective production, storage and dispensing of hydrogen as a transportation fuel. Worldwide, energy companies, automakers and petroleum companies are investing more than $2 billion annually to develop the hydrogen industry and diversify with new, sustainable sources of energy

- **Hydrogen: The Power and the Potential student curriculum:** This program provides an opportunity for students, guided by teachers and supported by the partnership of Progress Energy and the Florida Solar Energy Center, to step confidently forward into a new energy era. It will initially involve the following eight Florida schools:
  - Nature Coast Technical High School – Brooksville
  - Polk Avenue Elementary School – Lake Wales
  - J.W. Mitchell High School – New Port Richey
  - Lakewood High School – St. Petersburg
  - Lake Howell High School – Winter Park
  - Durance Elementary School – Orlando
  - Tuscawilla Middle School – Oviedo
  - Oak Ridge High School – Orlando

Interdisciplinary teams of teachers from the schools will participate in training facilitated by the Florida Solar Energy Center education staff. The teachers will review current curriculum and other information available on hydrogen to develop a unique curriculum that aligns with the Sunshine State Standards and their individual classes. As the population of Florida continues to increase, so does the need for resources, infrastructure and energy. The curriculum will serve as a model that could expand to other schools in the future. The goal is to help Florida make the transition to an economy that utilizes a variety of energy sources and technologies, including hydrogen.

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- **Uninterrupted Power Source powered by a hydrogen fuel cell:** Progress Energy is currently researching the feasibility of an alternative energy Uninterrupted Power Source (UPS) with a 5-kW hydrogen fuel cell. This demonstration project is taking place at the Palm Garden Assisted Living Facility on the west coast of Florida. The UPS hydrogen fuel cell will provide the power to essential lighting during power outages caused by hurricanes or other emergencies that can cause interruptions in grid power. The UPS hydrogen fuel cell project will help further the research and development of this technology for the future. This a joint project funded by Progress Energy and Plug Power.

Renewable Purchases

Pursuant to the Public Utility Regulatory Policies Act of 1978, Progress Energy purchases power from municipal solid waste incinerators and heat recovery/cogeneration plants in both the Carolinas and Florida.

- **Carolinas:** Progress Energy Carolinas purchases 16.2 MW of power from solid waste incinerators in the Carolinas and 10 MW from a heat recovery/cogeneration plant in North Carolina. The company also purchases power from small hydroelectric producers.

- **Florida:** Progress Energy Florida purchases 144 MW of power from municipal solid waste incinerators in Florida and 20 MW from four heat recovery/cogeneration plants.

Progress Energy has also agreed to purchase about 14 MW of electricity generated from landfill gas methane in central Florida, beginning in 2008. In addition, the company is in negotiations to purchase 120 MW of baseload generation to be generated from biomass gasification beginning in late 2007. The biomass for this project is a dedicated crop grown specifically for conversion into power, and it will be grown on 20,000 acres in central Florida. Once harvested, a proprietary pyrolysis technology will be used to convert the biomass into a bio-oil that will be used in a combined-cycle process to produce electricity.

NC GreenPower

NC GreenPower is a statewide program that encourages residential and business customers in North Carolina to support renewable energy development. More than 7,500 customers, including almost 2,300 Progress Energy customers, voluntarily pay $4 or more on their monthly electric bills to subsidize the purchase of renewable energy for the grid. Progress Energy is a "Champion" sponsor and played an active role in the program's development. The company markets the program, signs up participants and provides billing and collection services at no cost to the program. About 20 renewable energy generators are now under contract or are operating under this program, including solar, wood waste, small hydroelectric, animal biomass and landfill methane producers.

Hybrid Vehicles

Progress Energy is conducting a pilot project to evaluate the applicability and economic feasibility of including hybrid vehicles in its fleet. One Toyota Prius hybrid and one Ford Escape hybrid sport utility vehicle have been purchased for the pilot project. In addition, the company has reached an agreement with International Truck Company to purchase two hybrid International service bucket trucks when they become available in 2007.

Additional Climate Change Strategies

- **Integrated Gasification Combined Cycle (IGCC):** IGCC is part of Progress Energy's resource planning process, and the company regularly evaluates this and other emerging technologies as it makes generation decisions. The company completed a detailed coal gasification combined-cycle plant engineering study for a specific site in 2005, and the results of that study will be updated as the technology advances.

- **PowerTree Carbon Company:** Carbon sequestration, which is among the greenhouse gas reduction strategies recognized by the U.S. Energy Information Administration (EIA), is the means by which a biological process is used to convert CO_2 to biomass, making the gas unavailable to the atmosphere.

In 2003, Progress Energy joined 24 other electric power companies to establish the PowerTree Carbon Company, LLC. The companies have committed $3 million to establish six bottomland hardwood reforestation projects in the Lower Mississippi Alluvial Valley (LMAV) states of Louisiana, Mississippi and Arkansas. As the trees grow, they will capture 1.6 million tons of CO_2 from the atmosphere – as well as provide critical habitat.

- ***Carbon Burn-Out (CBO™):*** *Progress Materials, Inc., a subsidiary* of Progress Fuels Corporation, which is a wholly owned subsidiary of Progress Energy, has integrated its problem-solving skills, engineering capabilities and power plant expertise to create the patented CBO technology.

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The millions of tons of fly ash produced from coal-fired power plants have become increasingly difficult to landfill and recycle, but with CBO, Progress Materials has found a solution. Joe Cochran, a Progress Materials employee, invented this technology and received an award in 2003 from the National Energy Technology Laboratory of the U.S. Department of Energy.

CBO technology takes fly ash from coal-fired plants and "burns out" the residual carbon, producing a consistent, low-carbon, high-quality product proven to be valuable in the concrete industry. Every ton of fly ash used in concrete production instead of cement avoids at least 0.8 tons of CO_2 emissions.

CBO is currently used at two facilities in South Carolina, and two more facilities are under construction. When in full operation, these plants will avoid approximately 850,000 tons of carbon dioxide emissions every year.

- **Power Partners:** Progress Energy is a member of Power Partners, in partnership with the Edison Electric Institute (EEI) and the U.S. Department of Energy, along with other electric power industry groups. Power Partners is a voluntary partnership under which EEI, at the direction of its member companies, pledged to reduce the sector's carbon intensity by the equivalent of 3-5 percent in a decade.

- **Support of climate change research:** The Progress Energy Foundation contributed $150,000 in the fourth quarter of 2005 to the Carolina Environmental Program at the University of North Carolina at Chapel Hill, for the program's Sustainable Energy, Environment and Economic Development (SEEED) project. SEEED is an education and research project that encourages faculty and graduate students to examine sustainable energy in North Carolina. The Progress Energy grant will be used for applied research that will be useful to Progress Energy and the broader energy and policy community, and will provide information and analyses critical to the work of the state's Global Climate Change Commission.

- **Ash reuse:** Progress Energy produces approximately 1.8 million tons of coal ash each year. The electrostatic precipitators at the company's plants catch about 99.8 percent of the ash released from the boiler and in the flue gas. Some coal ash is recycled as an ingredient for use in concrete and other building and construction materials. Overall, the company reuses 41 percent of the fly ash captured at its facilities for recycling, including close to 100 percent at the Crystal River Plant in Citrus County, Fla.

Crystal River is comprised of one nuclear unit and four coal units – making it the largest plant on Progress Energy's system. Like all coal plants, the four coal units at Crystal River produce fly ash, particles that result from the burning of pulverized coal. Virtually all the fly ash at Crystal River is recycled into useful building products. Some fly ash is sold as feedstock to the cement industry and ends up in foundations, driveways and sidewalks. The rest is recycled in the onsite processing plant into Aardelite®, an aggregate used in lightweight concrete blocks. The recycling plant was built in 1988 and has produced 1.7 million tons of Aardelite, enough for 10 million concrete blocks.

- **Carbon sequestration project:** Progress Energy is partnering with the Southern States Energy Board, the Electric Power Research Institute (EPRI) and other utilities on a carbon sequestration study in the Carolinas. The study's scope will include both onshore and offshore areas.

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CARBON DIOXIDE
emissions modeling

Based on Progress Energy's forecasts of supply and demand, along with estimates for customer growth and electricity usage as indicated in section 6, the company's System Planning and Operations Department runs models to determine which generation sources may be needed and would be most cost effective for customers.

This process incorporates sophisticated resource optimization computer models to evaluate future generation alternatives. The integrated planning process looks at existing and new generation resources, efficiency and demand side management programs, and purchased-power contracts in a portfolio that will provide reliable electric service at a reasonable overall cost to Progress Energy's customers in the future.

Methodology

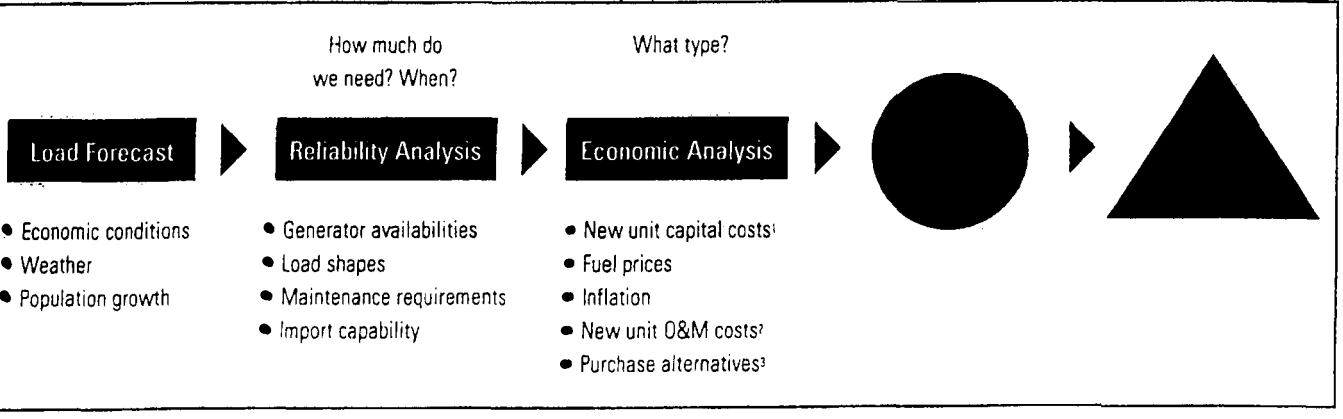
Progress Energy periodically assesses various generation technologies to ensure that projections for new resource additions capture new and emerging technologies over the company's planning timeframe. This analysis involves a preliminary screening of the generation resource alternatives based on commercial availability, technical feasibility and cost.

The commercial availability of each technology was first examined for use in utility-scale applications. For a particular technology to be considered commercially available, the technology must be able to be built and operated on an appropriate commercial scale. Reasonable levels of detail for emerging technologies were developed to allow Progress Energy to screen the technology options and to stay abreast of potential economic benefits as they mature.

Second, technical feasibility for commercially available technologies was considered to determine if the technology met Progress Energy's particular generation requirements and whether it would integrate well into the Progress Energy system. The evaluation of technical feasibility included the size, fuel type and construction requirements of the particular technology and the ability to match the technology to the service it would be required to perform on the system (e.g., baseload, intermediate or peaking).

Finally, for each alternative, an estimate of the levelized cost of energy production, or "busbar" cost, was developed. Busbar analysis allows for the long-term economic comparison of capital, fuel, and operations and maintenance costs over the typical life expectancy of a future unit at varying capacity levels.

Resource Planning Summarized



[1] New unit capital includes site costs. Sites are chosen to optimize fuel transportation and electrical transmission costs.

[2] New unit O&M costs include all applicable environmental costs.

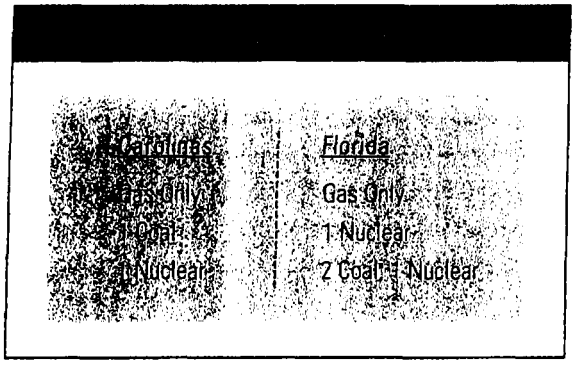
[3] Economic analysis may include an RFP to identify cost effective purchases.

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Assumptions

For this carbon price modeling, three resource plan scenarios were included for the Carolinas and Florida.

This was a one-dimensional model run, completed in August 2005. This modeling represents a snapshot in time, and the company updates its resource plans regularly.



Each combined-cycle power block (made up of 2 combustion turbines and 1 steam turbine) is assumed to produce about 500 MW; with gas-fired CTs producing about 150 MW each. Combustion turbines are essentially gas-fired turbines, similar to jet engines, which generate electricity.

Each coal unit is assumed to produce about 500 MW, and each nuclear unit assumed to produce about 1,000 MW.

For each scenario, a base case was established, and models were run with carbon prices of $0, $25 and $50, with a gas price set between $7.37 and $8.94 per million Btus.

In addition, each scenario also had one model run with a carbon price of $50, with a high gas price between $9.77 and $11.32 per million Btus. The high gas price used was from a fuel forecast the company receives, and the long-term high gas price forecast has not changed significantly after the hurricanes that affected the Gulf Coast of the United States.

The scenarios also assume that Progress Energy places its five smallest coal units in the Carolinas in "cold reserve," meaning that they would be available for emergency or peaking power. The Progress Energy Florida models include the repowering of the company's Bartow Plant from oil-fired to natural gas-fired, which was announced in 2005.

Renewables and Conservation

As part of these CO_2 emissions scenarios, Progress Energy did not run models specific to renewable resources or conservation programs, although the company did calculate reductions based on the assumptions

Renewable resources have many different operating characteristics. Wind power is available when sufficient wind is blowing. Solar power is available during the day time. A biomass burning generation facility may or may not have the capability to operate around the clock. The benefit of these resources is that they do not emit carbon dioxide. As renewable energy sources become more viable and cost effective, Progress Energy will coordinate with its state regulators to evaluate how they best fit into the company's generation mix.

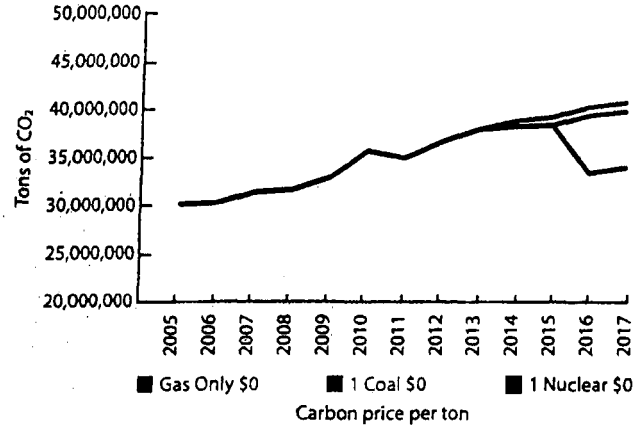
In general, replacing 1 percent of the company's total generation resources with renewable resources could yield a CO_2 reduction of up to 1.5 percent, because fossil-fueled generation makes up about 65 percent of the company's generation. Renewable resources would most likely replace the coal, gas or oil production. However, if the renewable resource generation is produced when the fossil plants are not running, the CO_2 reduction would be significantly reduced.

The same can be true for conservation programs. They have many different characteristics, and depending on when the conservation is taking place, 1 percent of total energy reduction from conservation programs could yield a CO_2 reduction up to 1.5 percent.

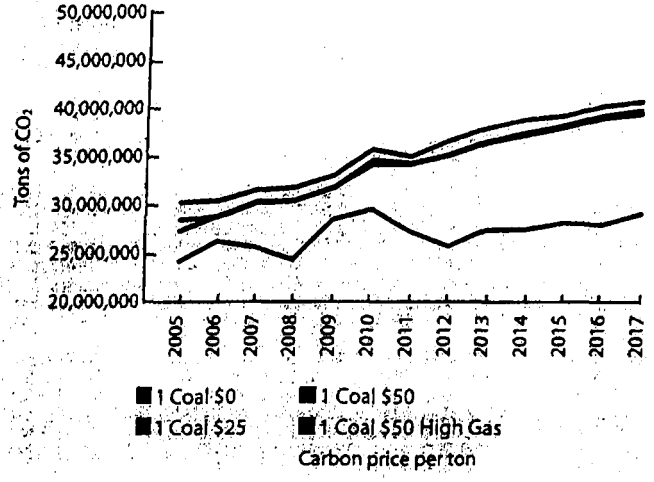
Outcomes

The charts that follow show the results of the CO_2 emissions modeling. The charts show anticipated carbon dioxide emissions associated with the three carbon prices.

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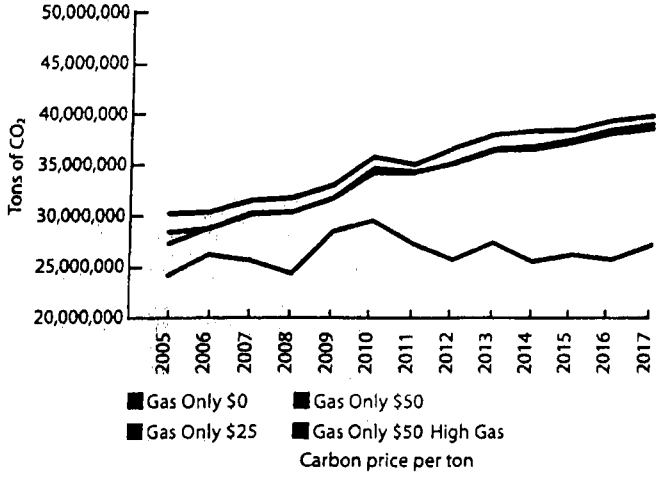


This chart shows the base case for carbon dioxide emissions for Progress Energy's service areas in the Carolinas, based on the company's resource plan from August 2005. If there were no carbon price regulation, and gas prices hold steady, the company's carbon dioxide emissions, as shown on the coal and natural gas curves, would continue to increase gradually through 2017. One new nuclear plant would result in a significant carbon dioxide decrease in 2016, which is when a new power plant would be expected to be operational, under the assumptions for this model.

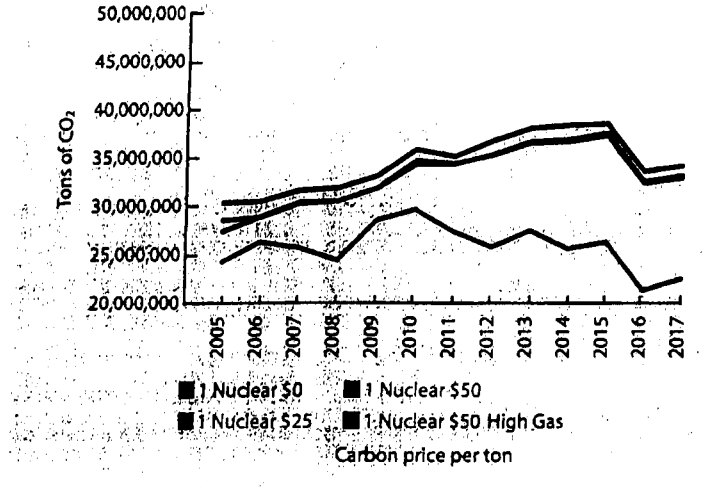


The coal plan assumes that the company would build one new coal plant in the Carolinas to meet demand. The top line shows that if no carbon price regulation is in place, the company would run its coal plants more to meet demand, particularly because coal is a cost-effective fuel source. A $25 per ton carbon price (shown in orange) results in a very small reduction in carbon dioxide emissions. A $50 carbon price (shown in purple), would result in a large reduction, because the company is required by its regulators to generate electricity at the least cost. Therefore, a $50 carbon price would make coal a less cost-effective option for the company. However, an increase in gas prices to between $9.77 and $11.32 per million Btus (shown in dark blue) would reduce the emissions benefits associated with the $50 carbon price, because it would still be more cost-effective to run the coal units.

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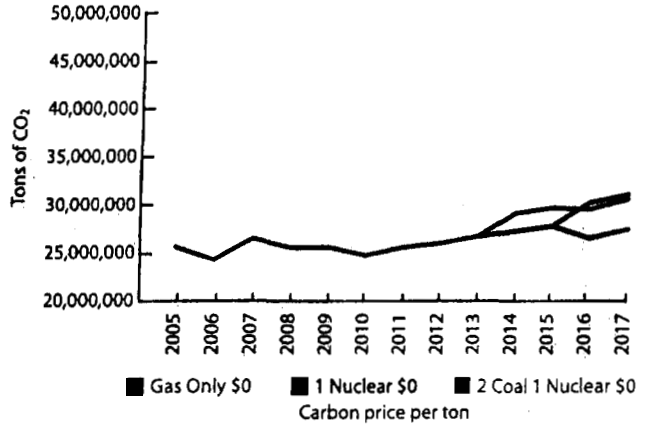


Under the gas plan, Progress Energy Carolinas would expand its fleet of natural gas units to meet intermediate and peaking demand. However, the company would still need to run its baseload coal and nuclear units to meet customer demand. The top line, in light blue, shows the expected carbon dioxide emissions if there is no carbon price. The orange line shows that a $25 per ton carbon price would have very little impact on carbon dioxide emissions. Only a $50 carbon price (shown in purple) would impact the company's resource mix, but that mix would not be affected if gas prices were between $9.77 and $11.32 per million Btus, as it would still be more cost-effective to produce electricity using coal.

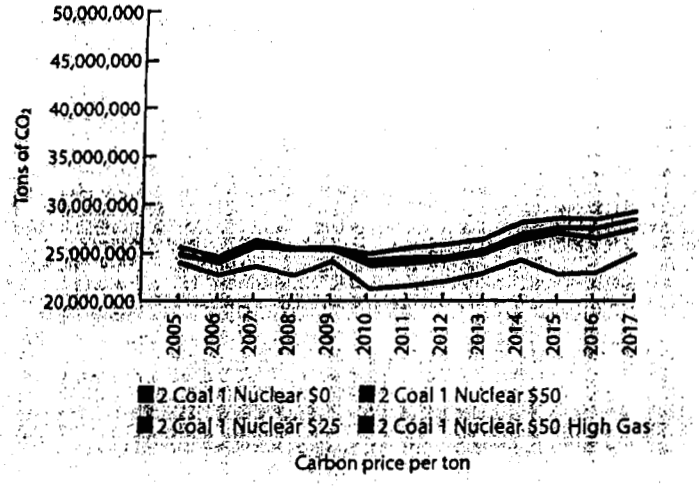


The nuclear plan assumes that Progress Energy Carolinas would build one nuclear unit, capable of producing 1,000 MW. The red line shows the impact of a $0 carbon price on carbon dioxide emissions, but emissions do drop in 2016, when a new nuclear plant would be online. The $25 per ton price (shown in orange) does show a slight decrease in carbon dioxide emissions, again with a bigger drop in 2016 when a nuclear plant would begin operating. The $50 per ton carbon price (shown in purple) again results in the largest decrease in carbon dioxide emissions, because it becomes less cost effective for the company to run its coal plants. As with the previous scenarios for the Carolinas, however, emissions reductions are not affected when gas prices are between $9.77 and $11.32 per million Btus (shown in dark blue).

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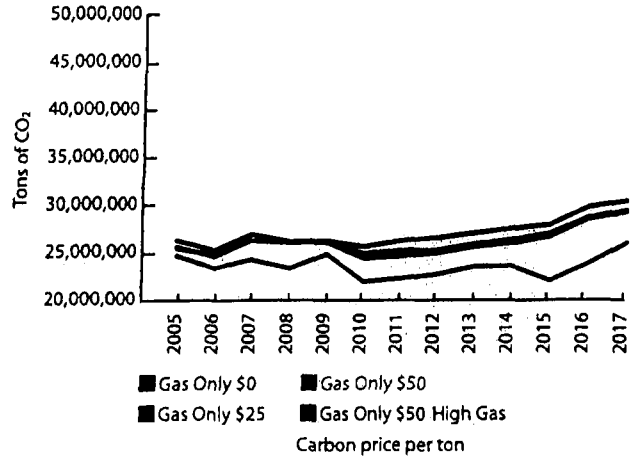


Progress Energy Florida's generation mix has more gas-fired generation and fewer coal-fired plants than the Carolinas. This chart shows the base case carbon dioxide emissions for Progress Energy Florida, under the modeling scenarios from August 2005. This chart shows that carbon dioxide emissions would remain steady through 2013, until the coal-fired generation (shown in green), comes online. Gas-fired generation (shown in blue) would increase the most under this scenario, although the emissions would not increase much more than those in the coal/nuclear plan (shown in green). The dips in 2016 in the nuclear plan and coal/nuclear plan indicate that a new nuclear plant would be online.

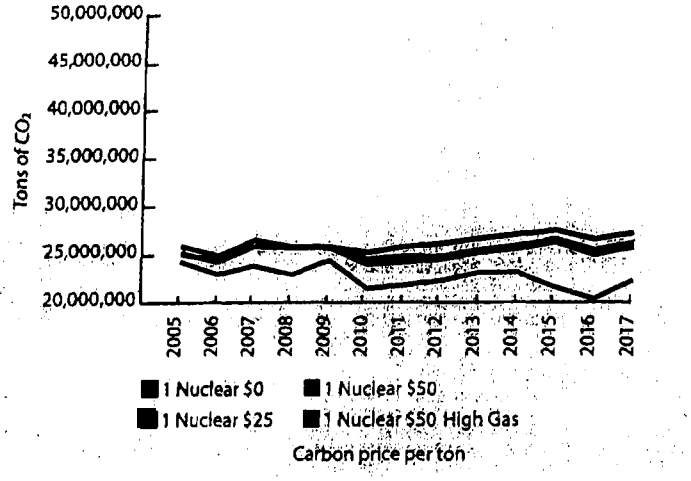


Progress Energy Florida's coal/nuclear plan assumes that two new coal units, producing a total of 1,000 MW, would be operating by 2013, and one new nuclear plant, also producing 1,000 MW, would be operating by 2016. The light green line shows carbon dioxide emissions if there were no carbon price. Again, because Florida has fewer existing coal units than the Carolinas, the differences between $0 carbon price and a $25 carbon price per ton are very small, although the $25 carbon price (shown in orange) does show some emissions reductions in the outlying years. A $50 carbon price (shown in purple) would result in the most carbon dioxide emissions reductions, because it would less cost-effective for the company to run its coal units at that price. However, as with the Carolinas scenarios, if gas prices were between $9.77 and $11.32 per million Btus (shown in dark blue), it would still be more cost effective to produce electricity using coal.

070007-Hearing Exhibit 000424



Progress Energy Florida's gas plan assumes that new gas units would meet rising demand. At a $0 carbon price (shown in light blue), carbon dioxide emissions would stay steady and increase slightly in the outlying years, with a $25 carbon price (shown in orange), tracking closely with the $0 price, although there is a slight decrease in the outlying years. A $50 carbon price (shown in purple), would result in a more significant decrease in carbon dioxide emissions, but in the outlying years, the emissions would begin to rise. Again, high gas prices (between $9.77 and $11.32 per million Btus) combined with a $50 carbon price (shown in dark blue) would result in fewer carbon dioxide emissions reductions, because the company would need to produce electricity using more cost-effective sources, including coal-fired generation.



Progress Energy Florida's nuclear scenario assumes that one new nuclear plant, producing 1,000 MW, would be in service by 2016. The nuclear plan does keep carbon dioxide emissions more level over time – at $0 (shown in red) and $25 (shown in orange). A $50 carbon price (shown in purple), would have the highest impact on carbon dioxide emissions because producing electricity using coal would be less cost-effective. However, high gas prices combined with a $50 carbon price (shown in dark blue), would result in the company running its nuclear and its coal plants more to meet demand, which would result in a less significant reduction in carbon dioxide emissions.

070007-Hearing Exhibit 000425

Conclusions

Carolinas

Because Progress Energy's service territory in the Carolinas includes more coal generation and because the area continues to experience growth in customers and in demand, carbon dioxide emissions are expected to steadily increase through 2017.

If Progress Energy builds a new coal-fired plant in the Carolinas, and no carbon price is instituted, the company would run its coal plants more to meet demand, particularly because coal is a cost-effective fuel resource. This would help the company maintain its regulatory compact to provide affordable, reliable electricity for customers. If carbon prices are instituted and reach $50, the company would need to run its coal plants less and use higher-priced alternatives, including gas-fired generation.

However, if the company does build a new nuclear plant, carbon dioxide emissions would decrease when the plant came online. It would be necessary for the company to continue to run its coal-fired units to meet demand, but having new baseload generation provided by nuclear power would decrease overall carbon dioxide emissions.

Florida

Progress Energy Florida's generation mix has more gas-fired generation and fewer coal-fired plants, making the initial carbon dioxide emissions and projections lower than the Carolinas. In addition, Progress Energy Florida's carbon dioxide emissions are forecast to remain steady until 2013, when the first projected new generation would come online, likely gas-fired or coal-fired generation.

If a new coal-fired power plant comes online in Florida, and no carbon price is in place, emissions would increase slightly – again because Progress Energy's Florida service territory has more natural gas-fired units in service.

As with the Carolinas, a new nuclear unit in Florida would result in a decrease in carbon dioxide emissions in 2016.

In all cases – for Progress Energy's service areas in the Carolinas and Florida – carbon dioxide emissions would be reduced when the carbon price was increased. However, when high gas prices are factored into the model, few changes are seen in the carbon dioxide emissions, with very little difference in emissions between the base case of a $0 carbon price and a $50 carbon price.

070007-Hearing Exhibit 000426

FUTURE CLIMATE
change options

As noted in the modeling analysis, the "cost of carbon" would play a major role in any future decisions on climate change strategies for Progress Energy. No single option or idea will address the complex issue of climate change. A balanced solution should be considered and acted upon in order to most effectively address this issue.

The company must consider the availability of a wide variety of solutions or ideas in its service areas. **Because these solutions vary in different regions of the country, Progress Energy is already researching and beginning to implement several options it believes are possible in the southeastern United States, including:**

- ☑ Clean coal technologies, including IGCC
- ☑ Repowering existing generation units
- ☑ Renewables, including biomass, wind and solar
- ☑ Expanded efficiency/DSM projects
- ☑ New nuclear generation

☑Clean Coal Technologies

IGCC

Progress Energy evaluates the cost effectiveness of commercially available and emerging technologies each year and also develops cost estimates for each of the technologies. The results are filed with state regulators each year as a part of the company's resource plan filing.

Technologies such as solar, coal gasification combined cycle (including potential CO_2 removal option), wind, biomass burning, tire burning, waste burning, fuel cell and traditional coal, gas, oil, and nuclear generators are all included in this annual evaluation. Progress Energy evaluates these technologies and includes generation resources that are cost effective in the company's resource planning modeling process.

Integrated gasification combined cycle (IGCC) technology is in Progress Energy's modeling database, and several evaluations were conducted for the company's baseload generation strategy development. Current studies indicate that coal technologies with carbon sequestration and storage have not been commercially proven, and there are no known places to store the carbon dioxide in the company's service area – the company would have to ship it out, adding more costs to such a project.

However, Progress Energy believes IGCC does hold promise, and the company will continue to monitor technology advancement and conduct feasibility studies to plan and develop its strategies. For example, a detailed coal gasification combined cycle plant engineering study was completed for a specific site in early 2005. The results of this study will be updated as the technology advances.

Other Clean Coal Projects

Progress Energy has conducted studies with the U.S. Department of Energy and Parsons, one of the largest engineering and construction firms in the United States, to examine the possibility of using advanced pressurized fluidized-bed combustion and circulating fluidized-bed combustion at two of its plants in North Carolina. These technologies use air, injected through the bottom of the furnace, to mix coal and a sulfur-absorbing material, such as limestone or dolomite, during combustion. Fluidized-bed combustion technologies can remove 90 percent or more of the sulfur dioxide from emissions and also significantly reduce emissions of nitrogen oxides.

Supercritical coal power plants, which use a much higher pressure steam and temperature in the combustion process and produce fewer emissions, have also been considered by the company in its annual planning. To date, however, this technology has not been the most cost-effective option to address demand and maintain customer rates.

While no decisions have been made to employ any of these options at this time, they remain under consideration as the company considers new baseload projects.

070007-Hearing Exhibit 000427

☑Repowering Existing Generation Units

Progress Energy announced in September 2005 that its Bartow Power Plant near St. Petersburg, Fla., would convert from an oil-fired power plant to a natural gas-fired plant. Such a move will reduce emissions and also:

- Increase the plant's output by 600 MW.
- Significantly decrease the use of heavy fuel oil, which will reduce barge traffic in Tampa Bay.

The Bartow Plant is located near Weedon Island's nature preserve, and the company is working with the Friends of Weedon Island and other community partners to ensure the construction is completed with as little impact as possible.

The $435 million project will begin in 2007 and is expected to be completed by 2010. The combined-cycle technology captures exhaust heat from the turbines to generate more power – so for the same amount of natural gas, the plant can produce up to 50 percent more electricity.

In addition, the company is considering repowering other plants in its service territory.

☑Renewables

Progress Energy is reviewing all technologies as it considers new base-load generation needs, including renewables. In making its decision, the company must consider affordability and reliability, as well as the economic and operational issues associated with any technology.

To date, the largest driver for the adoption of renewable energy resources has been the combination of legislative mandates at a state level and the increasingly competitive economics for alternative forms of energy, primarily wind power.

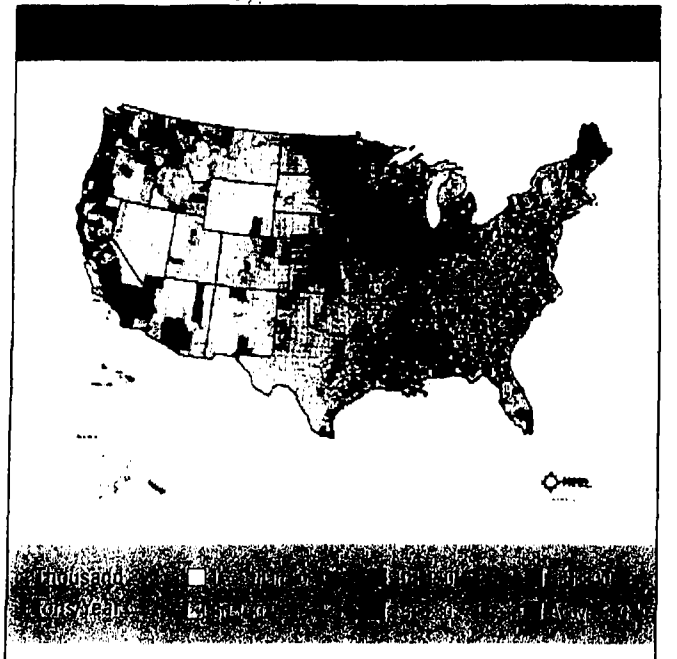
The vast majority of state mandates have been in conjunction with larger statewide deregulation efforts. While deregulation is not likely in the foreseeable future within Progress Energy's service territories, it is important for the company to understand the circumstances that have led to the adoption of renewable portfolio standards (RPS) in 20 states and the District of Columbia.

More than any other political driver, the potential for climate change legislation or regulation at the federal level could accelerate the widespread adoption of renewables.

As renewable energy sources become more viable and cost effective, Progress Energy will coordinate with its state regulators to evaluate how they best fit into the company's generation mix.

Biomass

The availability of renewable resources varies in Progress Energy's service area, with biomass, biogas, solar and several emerging off-shore technologies showing promise. In North Carolina alone, biomass has the estimated capability of providing 15.8 million MWh of annual electric generation. The map below shows the availability of biomass resources in the United States.



This study from the National Renewable Energy Laboratory estimates the technical biomass resources currently available in the United States by county. It includes the following categories:

- Agricultural residues (crops and animal manure)
- Wood residues (forest, primary mill, secondary mill and urban wood)
- Municipal discards (methane emissions from landfills and domestic wastewater treatment)
- Dedicated energy crops (on Conservation Reserve Program and Abandoned Mine Lands)

This map shows the availability of biomass resources in the United States. Many areas of Progress Energy's service territory, particularly eastern North Carolina and northeastern South Carolina show biomass potential.

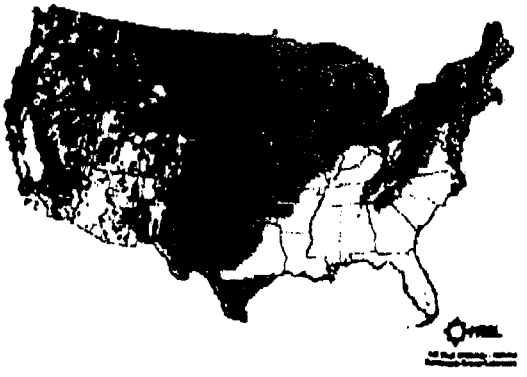
070007-Hearing Exhibit 000428

Co-firing biomass is a mature technology that aligns well with Progress Energy's core technical competencies. Progress Energy has the tools and processes already in place to evaluate these renewable fuel sources on a trial basis, and the company is scheduled to begin its first biomass co-firing trial at the Sutton Plant in Wilmington, N.C., in 2006.

Additionally, apart from any fuel handling modifications, this option uses all of Progress Energy's existing generation and transmission infrastructure. Animal waste co-firing has an additional benefit of reducing environmental issues associated with North Carolina's current waste-management systems. Progress Energy also supports the efforts of researchers looking at using hog waste and turkey litter as a fuel.

Wind

Nationwide, wind is the most cost competitive and fastest-growing form of renewable energy. In Progress Energy's service territories, land-based wind is not as widely available, as shown in the map from the National Renewable Energy Laboratory.



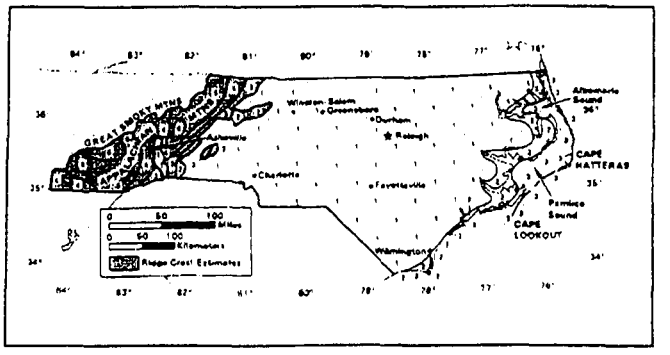
Wind Power Class	Wind Resource Potential
6	Outstanding
5	Excellent
4	Good
3	Fair
2	Marginal
1	Poor

Federal and Oklahoma Indian Land Boundaries

Land-based wind resources are not readily available in the southeastern United States, with most of the region noted as having "poor" potential.

Source: National Renewable Energy Laboratory

Land-based wind generation requires significant capital investment, and is limited in the company's service territory to a few mountain ridge areas in western North Carolina. Any developments in those areas must address the Mountain Ridge Protection Act of 1983, which protects many of the state's ridges from development. Even if construction of wind turbines were permitted on North Carolina's mountain ridges, there are significant issues in siting and building transmission lines in those areas to carry the energy to consumers. In addition, there are other environmental considerations associated with wind, including noise and animal impacts.



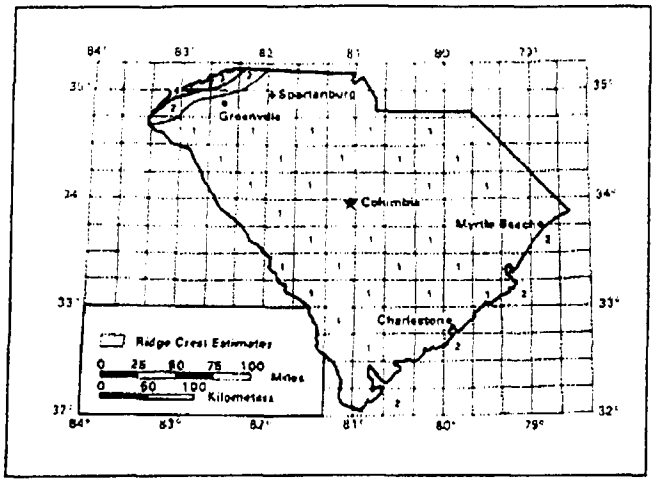
Source: National Renewable Energy Laboratory. *Wind energy in North Carolina is most available offshore or in the mountains, which can cause transmission challenges.*

While the availability of land-based wind resources is fairly limited within Progress Energy's service territories, offshore wind resources and tidal resources are more available, as shown on these maps, also from the National Renewable Energy Laboratory.

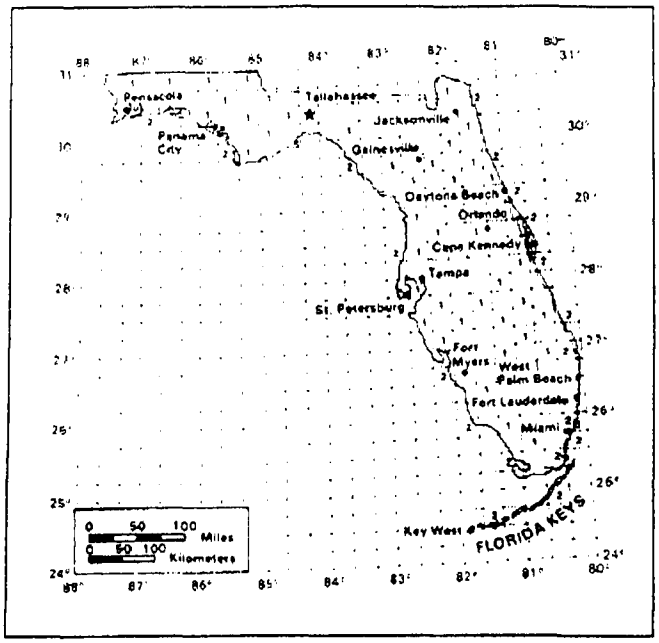
Increasing offshore development will be based on many factors, including cost, permitting, regulatory approval and public and political support.

While no offshore wind farms are now operating within the United States, many have been operating in Europe since 1991, and the 420 MW Cape Wind project in Massachusetts is scheduled to go online in 2009. Likewise, there are no current tidal power plants operating in the United States, but plants have been in operation in Canada and Europe since the 1960s.

070007-Hearing Exhibit 000429



Source: National Renewable Energy Laboratory. *There is little to no wind availability in our service territories in South Carolina and Florida, according to the NREL.*



Solar

Progress Energy has supported solar photovoltaic and solar thermal projects in its service area for many years, particularly in Florida. In 2006, the company is working on the following solar projects:

- **Solar Thermal Water Heating Pilot:** In Seminole County, Fla., the company has installed and will test six solar thermal water heating systems for one year, monitoring total energy savings and system efficiency.

- **Expansion of SunSmart School Program:** Four additional schools in Progress Energy Florida's service territory will become part of the SunSmart School Program, in partnership with the Florida Department of Environmental Protection (FDEP) and Florida Solar Energy Center (FSEC). Three of the schools will install a 4-kW PV system, and one school will have a 10-kW system with battery backup. This school is designated as an emergency shelter facility, and the PV system and battery backup will help ensure that the school maintains electric service during emergency situations, such as hurricanes.

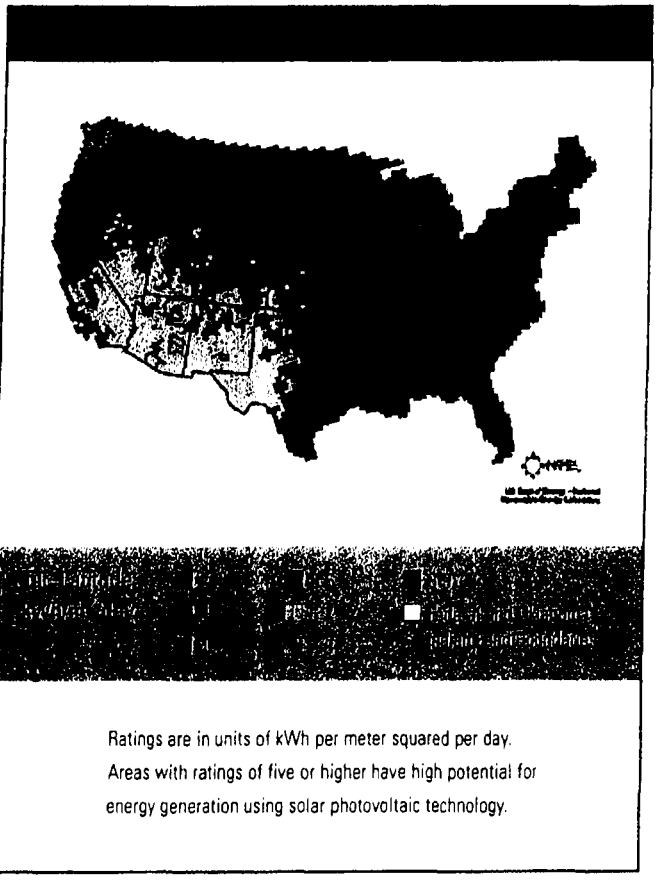
- **Expansion of Econolochatchee Photovoltaic Array:** In addition to an existing amorphous silicon array, which was installed in 1988 at the Econolochatchee substation in Orlando, Fla., three new solar technologies will be tested at the site, including crystalline silicon, bifacial and high-efficiency modules. Each technology will feed a separate inverter to transfer energy to the grid. Progress Energy will compare the power output, efficiency, reliability and energy production of each technology.

070007-Hearing Exhibit 000430

- Solar Hybrid Lighting Project: Two commercial customers are participating in this pilot project with Progress Energy Florida. The photovoltaic system also has integrated dimming, meaning it will turn lights off in the building if enough sunshine is available to light the building, resulting in increased efficiency.

In North Carolina, the company supports solar projects through the NC GreenPower program, which provides funds to independent power producers, many of whom are generating electricity with solar photovoltaics.

In the future, the company will continue to pilot promising solar technologies and will continue its partnerships with Florida Department of Environmental Protection, Florida Solar Energy Center and NC GreenPower on these initiatives.



Ratings are in units of kWh per meter squared per day. Areas with ratings of five or higher have high potential for energy generation using solar photovoltaic technology.

This map from the National Renewable Energy Laboratory shows the potential for solar photovoltaic use in the United States. Almost all of Progress Energy's service territory ranks five or higher, meaning there is potential for the use of solar photovoltaics for electric generation in these areas.

☑Expanded Efficiency/DSM Projects

For the future, Progress Energy is looking at aggressive promotion of existing energy-efficiency programs (detailed in section 8), including potentially strengthening demand side management programs. The company hopes to build on the success of these existing and past programs, which have reduced electricity usage by more than 26 billion kWh since 1981.

Progress Energy is also reviewing programs for potential expansion into all parts of the service territory. For example, in the Carolinas, the company has begun discussions with key stakeholders about expansion of its energy-efficiency and DSM programs. Formal DSM programs will need incentives, particularly cost recovery for energy producers, to be effective.

Because of existing DSM programs in Florida, it is easier to expand and promote them with customers, but the company is also looking at how to successfully implement such programs in the Carolinas with continued load growth in those states.

Progress Energy is committed to continuing to work with state regulators and stakeholders to develop cost-effective energy-efficiency and demand side management choices for customers.

☑New Nuclear Generation

Progress Energy's expected growth in the coming years, both from an increasing number of customers and increasing demand, will require significant increases in the amount of electricity the company is able to produce.

The state utilities and public service commissions that regulate Progress Energy require that electricity be produced in the most affordable, reliable manner possible for customers. As noted previously, the company looks closely during its resource planning process at technologies that will meet those requirements.

The chart on page 33 shows the comparison between different electric generation technologies and sources, using 30-year levelized costs. The assumed capacity factor is shown for each electric generation technology, and the total cents/kWh adds together the capital costs, fuel costs and operating costs associated with these technologies over their projected service life.

070007-Hearing Exhibit 000431

The chart shows that nuclear and coal-fired generation, which would be expected to have the highest capacity factors, potentially yield the lowest costs to produce electricity. IGCC also is becoming more competitive. While wind power is also becoming more competitive, its capacity factor is lower.

Nuclear	90%	3.93
Coal	90%	4.18
Combined Cycle	50%	6.13
Combustion Turbine	10%	12.64
IGCC	90%	4.54
Wind	30%	5.55
	20%	8.32
Solar	30%	18.84
	20%	28.27
Distributed Gas	90%	9.40

71-100% capacity = baseload
11-70% = intermediate
0-10% = peaking

**Source: Calculations based on EPRI TAG and Progress Energy fuel estimates.*

In addition to the cost considerations, the only technology available today to meet the demand growth in the time required with no associated greenhouse gas emissions is nuclear power. Additional nuclear generation also helps the company comply with tightening clean air rules, including the Clean Smokestacks Act in North Carolina and the federal Clean Air Interstate Rule, Clean Air Mercury Rule and Clean Air Visibility Rule.

There are uncertainties associated with new nuclear technologies, a new licensing process and the resolution of spent fuel storage in the future. The decision to build a nuclear plant will be based on several factors including fuel prices, the regulatory environment and public and policy-maker support.

Progress Energy believes that these risks are manageable, and the company is keeping nuclear power as an option in its future generation planning. This balanced approach also includes more conservation and energy efficiency programs, clean coal technologies and the development of new energy technologies, along with the potential for renewable and alternative energy sources.

The company informed the Nuclear Regulatory Commission (NRC) in August 2005 of its plans to submit a combined license application for a nuclear power plant. It updated those plans Nov. 1, 2005, to include a second application, one for Florida and one for the Carolinas. Each application covers up to two reactors at each site.

This step is necessary to obtain a license should the company decide that a new nuclear unit is the best option for meeting the need for additional generation. The application could be filed in late 2007 or early 2008. If approved by the NRC – and if the decision to build is made – construction could begin as early as 2010, and a new plant could be online around 2016.

The licensing process, once completed, gives the permit holder the option to construct and operate units on a specific site – it does not obligate the company to build.

A final decision to build another nuclear plant is still several years away. In order to provide the most reliable, safe and efficient mix of energy resources for its customers, Progress Energy is taking steps now to keep the option for nuclear open and viable in the future.

In January 2006, Progress Energy chose the Harris site, located near New Hill, N.C., after evaluating several sites in the Carolinas, based on its available land, transmission lines and proximity to cooling water and to Progress Energy Carolinas' largest area of customer concentration.

In Florida, the company expects to complete its evaluation of several potential sites in the first part of 2006. Just like the process in North Carolina, the selection of a site in Florida only begins the application process and does not commit the company to building a new nuclear unit. The company wants to keep the option open to expand its nuclear generating capacity in both states while it continues to evaluate energy demand and economic conditions and works with key leaders, regulators and the communities to determine the best options to meet the needs of its growing customer base.

070007-Hearing Exhibit 000432

Conclusion

Progress Energy recognizes that global climate change is a significant issue that presents business risk to the company, *and social, economic and environmental risks to the areas it serves.*

While participating in the national policy debate, we will work with stakeholders in our region to develop consensus-based strategies to address climate change and help our region succeed as future national policies are implemented.

In addressing this issue, the company must balance economic and environmental issues with its obligation to provide affordable, reliable electricity to its customers. To achieve these objectives, the company will employ a multipronged, balanced approach by boosting conservation and efficiency programs, increasing the use of renewable sources of energy and using nuclear power and potentially clean coal technologies to address demand and customer growth.

070007-Hearing Exhibit 000433

CAUTION REGARDING
forward-looking information

This report contains forward-looking statements within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The matters discussed throughout this report that are not historical facts are forward-looking and, accordingly, involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

Any forward-looking statement is based on information current as of the date of this report and speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: the impact of fluid and complex laws and regulations, including those relating to the environment and the recently enacted Energy Policy Act of 2005; the financial resources needed to comply with environmental laws; deregulation or restructuring in the electric industry that may result in increased competition and unrecovered or stranded costs; weather conditions that directly influence the demand for electricity; the ability to recover through the regulatory process costs associated with future significant weather events; recurring seasonal fluctuations in demand for electricity; fluctuations in the price of energy commodities and purchased power; economic fluctuations and the corresponding impact on our commercial and industrial customers; the ability of our subsidiaries to pay upstream dividends or distributions; the impact on our facilities and businesses from a terrorist attack; the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks; the anticipated future need for additional baseload generation in our regulated service territories and the accompanying regulatory and financial risks; the ability to successfully access capital markets on favorable terms; our ability to maintain current credit ratings and the impact on our financial condition and ability to meet our cash and other financial obligations in the event our credit ratings are downgraded below investment grade; the impact that increases in leverage may have on us; the impact of derivative contracts used in the normal course of business; the investment performance of our pension and benefit plans; our ability to control costs, including pension and benefit expense, and achieve our cost-management targets for 2007; the availability and use of Internal Revenue Code Section 29/45K (Section 29/45K) tax credits by synthetic fuel producers and our continued ability to use Section 29/45K tax credits related to our coal-based solid synthetic fuel businesses; the impact that future crude oil prices may have on the value of our Section 29/45K tax credits; our ability to manage the risks involved with the operation of nonregulated plants, including dependence on third parties and related counter-party risks, and a lack of operating history of such plants; the ability to manage the risks associated with our energy marketing operations, including potential impairment charges caused by adverse changes in market or business conditions; the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements; and unanticipated changes in operating expenses and capital expenditures. Many of these risks similarly impact our nonreporting subsidiaries.

These and other risk factors are detailed from time to time in our filings with the United States Securities and Exchange Commission (SEC). All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond our control. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can it assess the effect of each such factor on us.

070007-Hearing Exhibit 000434

Appendices

APPENDIX 1:
Air Quality Programs and Proposals (Regulatory & Legislative)

The Clean Air Act

The Clean Air Act has required states to regulate emissions of pollutants shown to have health impacts since the 1970s. These standards are called the National Ambient Air Quality Standards (NAAQS). For electric utilities, this has meant restrictions on emissions of particulate matter (PM), sometimes measured by the appearance of the smoke leaving a stack, nitrogen oxides (NOx) and sulfur dioxide (SO_2). Emissions of NOx are regulated because they form ozone, a pollutant that can have respiratory effects at high concentrations. Emissions of both NOx and SO_2 form compounds in the atmosphere that form fine particulate matter that has been shown to have both respiratory and cardiovascular effects.

When the Clean Air Act was amended in 1990, Congress created a new program to reduce the environmental impacts caused by acid deposition, or "acid rain" created by utility emissions. This program, under Title IV of the Clean Air Act amendments, required additional reductions on NOx and SO_2. The program used a new approach to regulation by creating a national cap on emissions, allocating allowances to the emitting units, and then allowing the owners of the emitting units to decide the best method of compliance. Some installed controls or switched to lower-sulfur coals, while some bought allowances from others. This market-based control program for SO_2 under the Title IV program has been one of the most successful environmental programs ever implemented, with a near 100 percent compliance record.

In 1997, the U.S. Environmental Protection Agency (EPA) strengthened the health-based standards for ozone and fine particulate matter (particulate matter less than 2.5 parts per million in diameter, or PM 2.5) based on new scientific data on health effects. This triggered a requirement for the states to revise their plans for meeting the new, lower standards. The EPA has developed several new regulatory programs to help states attain these standards, including several discussed below.

NOx SIP Call

Despite years of effort, many states had difficulty meeting the EPA's standard for ozone. Improved scientific understanding of the formation of ozone indicated that part of the problem was due to the emissions coming from other states. The NOx State Implementation Plan (SIP) Call was developed by EPA to reduce the transport of ozone precursors so that the downwind states could meet the ozone standard. This rule requires utilities and other large stationary sources in certain Eastern and Midwestern states to reduce emissions of NOx during the summer months when ozone is most likely to form. Like the Title IV (acid rain) rules, the NOx SIP Call is a trading rule. Utilities and large industrial sources can control some or all of their units, buy allowances to meet any shortage and sell extra allowances if possible.

Clean Air Interstate Rule (CAIR)

The Clean Air Interstate Rule (CAIR) was finalized by the EPA in March 2005 and must be implemented by 28 Eastern states and the District of Columbia. This rule helps states meet the 1997 ozone and PM 2.5 standards by requiring further reductions in the precursor pollutants, NOx and SO_2, that are transported across state lines. This rule builds on the Title IV (acid rain) rules by requiring a further 50 percent reduction in SO_2 emissions by 2010 and a 67 percent reduction by 2015. Additional NOx reductions are required, this time on an annual basis instead of just during the summer months. States are encouraged to implement the CAIR by implementing a trading program, but it is not required.

In addition to requiring additional reductions, this rule requires NOx reductions over a wider area, including Florida for the first time. Florida was not included in the NOx SIP Call.

070007-Hearing Exhibit 000435

Clean Air Visibility Rule (CAVR)

The Clean Air Act required that EPA establish a program to reduce visibility impacts, or regional haze, in national parks. The act required that certain emission sources, including electric generators, built between 1962 and 1977 install Best Available Retrofit Technology (BART) to control emissions such as SO_2 and NOx that can form haze. The Clean Air Visibility Rule, finalized in June 2005, provides guidelines for states to use in determining BART. For electric utilities subject to CAIR, compliance with the requirements of CAIR satisfies BART for emissions of NOx and SO_2 because EPA has determined that greater reductions will result from CAIR than from BART controls alone.

Clean Air Mercury Rule (CAMR)

The third of the clean air rules of 2005 issued by EPA is the Clean Air Mercury Rule (CAMR). Because emissions of mercury can be controlled to some extent by the same equipment that is used to reduce emissions of NOx and SO_2, EPA has coordinated the two rules both in timing and by relying on market-based cap-and-trade programs for both regulations. Under CAMR, coal-fired electric generating units must reduce emissions of mercury to a nationwide total of 38 tons by 2010 and to 15 tons by 2018. Like CAIR, this rule must be implemented by states.

Revisions to Particulate Matter (PM) and Ozone Standards

Most of the EPA rules discussed above were designed to address the 1997 revisions to the PM and ozone standards. EPA is required to evaluate these standards every five years, so this process is again under way. EPA staff has made preliminary recommendations to change the PM rule, further tightening the standard. It is not yet known whether EPA will also recommend changes to the ozone standard. Either of these could require additional NOx and SO_2 controls at electric utility units.

North Carolina Clean Smokestacks Act

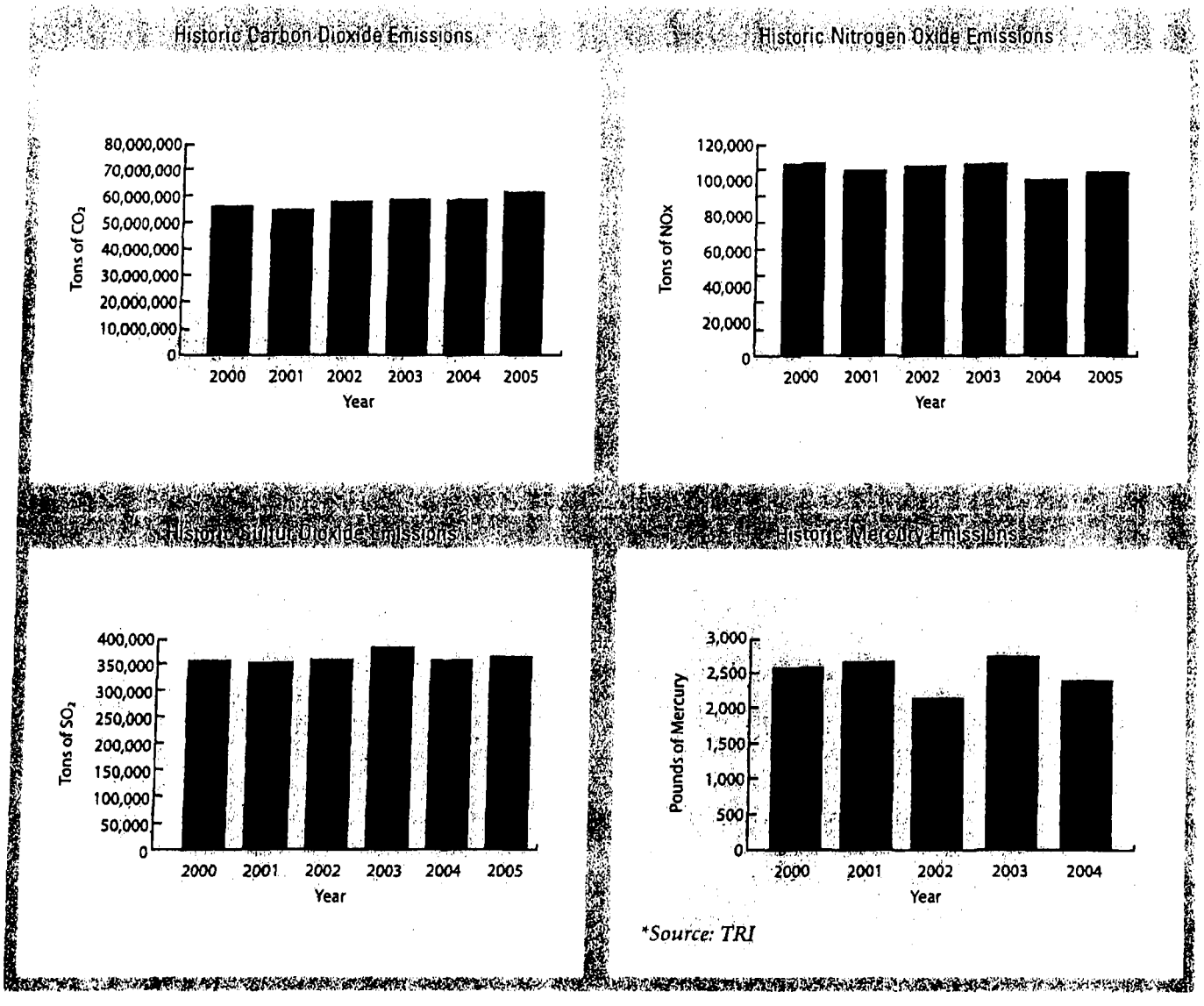
In June 2002, the North Carolina General Assembly passed the landmark Clean Smokestacks Act. This law reduces NOx and SO_2 emissions from coal-fired power plants in North Carolina by setting caps on each system operated by the two major electric utilities – Duke Power and Progress Energy. These reductions are comparable in scale to the reductions required under the EPA's CAIR rule, but cannot be achieved by trading. In addition to the substantial reductions in NOx and SO_2 emissions, the controls installed to meet this rule are expected to achieve a 65 percent reduction in mercury emissions in North Carolina.

070007-Hearing Exhibit 000436

APPENDIX 2

Progress Energy Emissions Data

070007-Hearing Exhibit 000437



Progress Energy's emissions of carbon dioxide, nitrogen oxides, sulfur dioxide and mercury have remained steady since 2000, despite a continuing increase in the number of customers and demand for electricity, resulting in the need to run the company's coal-fired power plants at a higher capacity factor. In 2003, the company also ran its coal units more to meet demand while a nuclear unit was in a scheduled outage.

As the company continues to install emissions-reduction technologies to meet the requirements of the North Carolina Clean Smokestacks Act, Clean Air Interstate Rule and Clean Air Mercury Rule, emissions of sulfur dioxide, nitrogen oxides and mercury will decrease. Currently, no technologies are commercially available to reduce carbon dioxide emissions from coal-fired power plants.

070007-Hearing Exhibit 000438

APPENDIX 3

Correspondence with Shareholder Groups

The attached pages include written correspondence between the shareholder groups and Progress Energy.

070007-Hearing Exhibit 000439



BOSTON COMMON
ASSET MANAGEMENT, LLC

November 23, 2004

Mr. John R. McArthur
Senior Vice President – Progress Energy Service Company,
General Counsel and Corporate Secretary
Progress Energy, Inc.
410 S. Wilmington Street
Raleigh, NC 27601-1748

Dear Mr. McArthur:

Boston Common Asset Management, LLC (Boston Common) is an investment manager that serves investors concerned about the social and environmental impact, as well as the financial return, of their investments. We are writing to you regarding the substantial emissions of carbon dioxide and other pollutants by Progress Energy and your lack of adequate information disclosure to shareholders on this issue. This leads us to believe our company has not fully considered climate change risks nor does it have a viable plan for managing them.

We are part of a larger shareholder group seeking to expand the important dialogue on climate change throughout the electric power industry. Boston Common is writing on behalf of a group of shareholders including our client the Brethren Benefit Trust, Inc. (BBT) and The City of New York Office of the Comptroller. BBT is the financial arm of the Church of the Brethren. BBT holds approximately 1,700 shares of Progress Energy Inc. common stock. Our client, BBT, has authorized us to file the enclosed shareholder proposal on their behalf. As a religiously sponsored organization, BBT seeks to reflect its values, principles and mission in its investment decisions.

As shareholders, we are deeply interested in how Progress Energy is responding to the multiple risks global climate change presents to electric power companies. With regulation to address greenhouse gas (GHG) emissions emerging at global and regional levels, we are interested in our company's plan to address the strong possibility of GHG emission cap legislation. Scientists as well as shareholders have demonstrated significant concern over climate risks and we hope our company will begin to assume a leadership role in this area and seize opportunities to be on the frontier of cleaner power generation. Last year, investors identified numerous companies in the industry as having significant exposure to climate change risks. Shareholder proposals were filed at many of these companies requesting a report on climate change and plans for managing it. Several companies and direct competitors, including American Electric Power, Cinergy, Southern Company and TXU, agreed to issue reports to shareholders on this issue. We believe that these concerns apply to our company as well.

Our stakeholder group would like to initiate a dialogue with you on these critical issues. We consider the following to be the key elements that must be addressed openly by our company:

- The extent to which our company has established, or plans to establish, an appropriate absolute greenhouse gas reduction goal
- Our company's plans to implement comprehensive and verifiable public reporting of its greenhouse gas emissions (via a commonly accepted measurement protocol)

- Our company's plans to assess and disclose its exposure to climate change risks and opportunities under a variety of regulatory scenarios
- Our company's position on mandatory limits for greenhouse gases in the United States and other climate change policy solutions

At present we do not believe Progress Energy is addressing the issues outlined above as fully as necessary and we would thus like to discuss them in a substantive manner with our company. As you are aware the deadline for filing a shareholder proposal is approaching. Therefore, to protect our rights as shareholders, we are submitting the enclosed shareholder proposal for inclusion in the 2005 proxy statement, in accordance with Rule 14a-8 of the General Rules and Regulations of the Securities Exchange Act of 1934, ("the Act"). Brethren Benefit Trust, Inc. (BBT) is the beneficial owner, as defined in Rule 13d-3 of the Act, of 1,700 shares of Progress Energy, Inc. common stock. BBT has held at least $2,000 in market value of these securities for more than one year as of the filing date and will continue to hold at least the requisite number of shares for proxy resolutions through the stockholders' meeting. Verification of ownership is forthcoming. Boston Common is the primary filer of this resolution on behalf of its client, the Brethren Benefit Trust. A representative of the filers will attend the stockholders' meeting to move the resolution as required.

We look forward to hearing from you. We hope that we may discuss our proposal further and reach a mutually satisfactory agreement that may allow us to withdraw our proposal. Please send all correspondence related to this matter to my colleague Dawn Wolfe at Boston Common Asset Management, 84 State Street, Suite 1000, Boston, MA 02109. Ms. Wolfe can be reached by phone at (617) 720-5557, via fax at (617) 720-5665, or via email at dwolfe@bostoncommonasset.com, if you have any questions.

Sincerely,

Steven Heim

Steven Heim
Director, Social Research

Encl. Resolution Text

cc: Will Thomas, Director of Foundation Operations, Brethren Benefit Trust, Inc.
Patrick Doherty, Bureau of Asset Management, The City of New York Office of the Comptroller

CLIMATE CHANGE REPORT

PROGRESS ENERGY, INC.

WHEREAS:

A 2004 report by the Bush Administration's Climate Change Science Program stated that increases in human-derived greenhouse gas emissions are the only likely explanation for global warming over the past three decades.

A 2004 Conference Board report declared that, "scientific consensus that the climate is changing is growing steadily stronger over time; Corporate boards will be increasingly expected to evaluate potential risks associated with climate change; and, the global economy will become less carbon-intensive over time...The real questions are what the pace of the transition will be and who will be the winners and losers."

U.S. power plants are responsible for nearly 40 percent of the country's carbon dioxide emissions, and 10 percent of global carbon dioxide emissions. Scientists estimate that about 160,000 people die yearly from side-effects of global warming ranging from malaria to malnutrition and the numbers could double by 2020.

A 2003 Department of Defense report outlined a plausible abrupt climate change scenario that "would challenge the United States national security in ways that should be considered immediately."

An August 2004 *Business Week* cover story noted that executives at AEP, Exelon and Xcel are preparing for mandatory carbon dioxide emissions constraints. Developments include: more than 90 countries ratifying the Kyoto Protocol; eleven Governors pledging to reduce emissions significantly; and renewable energy standards in sixteen states, indicating increasing support for non-polluting electricity sources. In October 2003, 43 U.S. Senators voted in favor of legislation to cap greenhouse gas emissions from a range of industrial sectors.

Recent reports by CERES, The Carbon Disclosure Project, Innovest Strategic Value Advisors, and the Investor Responsibility Research Center demonstrate the growing financial risks of climate change for US corporations.

Attorneys general from eight states have filed a public nuisance lawsuit demanding that Cinergy, American Electric Power Co., Southern Co., Xcel Energy and Tennessee Valley Authority reduce carbon dioxide emissions 3 percent per year for the next 10 years.

In a July 2004 *Newsweek* story, the insurance company AXA estimated that 20 percent of global GDP is affected by climatic events and, "climatic risk in numerous branches of industry is more important than the risk of interest rates or foreign exchange risk."

In 2004, AEP, Cinergy, TXU, and Southern Company agreed to issue comprehensive reports to shareholders about their financial exposure under potential emissions control scenarios. AEP stated, "some initial mandatory reductions of greenhouse gas emissions are likely in the next decade, the economic impact of controlling greenhouse gas and other emissions thus depends on the company's ability to meet these goals... Management and the Board have a fiduciary duty to carefully assess and disclose to shareholders appropriate information on the company's environmental risk exposure."

RESOLVED: The shareholders request that a committee of independent directors of the Board assess how the company is responding to rising regulatory, competitive, and public pressure to significantly reduce carbon dioxide and other emissions and report to shareholders (at reasonable cost and omitting proprietary information) by September 1, 2005.

THE CITY OF NEW YORK
OFFICE OF THE COMPTROLLER
1 CENTRE STREET
NEW YORK, N.Y. 10007-2341

WILLIAM C. THOMPSON, JR.
COMPTROLLER

November 30, 2004

Mr. John R. McArthur
Sr. Vice President – Progress Energy Service Co.
General Counsel and Corporate Secretary
Progress Energy, Inc.
410 S. Wilmington Street
Raleigh, NC 27601-1748

Dear Mr. McArthur:

The Office of the Comptroller of New York City is the custodian and trustee of the New York City Employees' Retirement System (the "system"). The system's board of trustees has authorized me to inform you of our intention to offer the enclosed proposal for consideration of stockholders at the next annual meeting.

I submit the attached proposal to you in accordance with rule 14a-8 of the Securities Exchange Act of 1934 and ask that it be included in your proxy statement.

Letters from Citibank and Bank of New York certifying the system's ownership, continually for over a year, of shares of Progress Energy common stock are enclosed. The system intends to continue to hold at least $2,000 worth of these securities through the date of the annual meeting.

We would be happy to discuss this initiative with you. Should the board decide to endorse its provisions as company policy, the system will ask that the proposal be withdrawn from consideration at the annual meeting. Please feel free to contact me at (212) 669-2651 if you have any further questions on this matter.

Very truly yours,

Patrick Doherty

Enclosures

Progress energy 04-05

CLIMATE CHANGE REPORT

PROGRESS ENERGY, INC.

WHEREAS:

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RESOLVED: The shareholders request that a committee of independent directors of the Board assess how the company is responding to rising regulatory, competitive, and public pressure to significantly reduce carbon dioxide and other emissions and report to shareholders (at reasonable cost and omitting proprietary information) by September 1, 2005.

Progress Energy

John R. McArthur
Vice President
Corporate Counsel and Secretary

February 18, 2005

Dawn Wolfe
Social Research and Advocacy
Boston Common Asset Management, LLC
84 State Street, Suite 1000
Boston, MA 02109

Re: Shareholder Resolutions – Global Climate Change

Dear Ms. Wolfe:

We appreciated the opportunity to speak with you, Patrick Doherty, Steven Heim and Dan Bakal with regard to the proposed shareholder resolutions concerning risks associated with global climate change. This letter memorializes the commitments that the Company proposes to make in return for an agreement by the Office of the Comptroller of New York City and Brethren Benefit Trust to withdraw the resolution proposals submitted to Progress Energy on November 23rd and 30th, 2004.

In summary, the Company will prepare a report that encompasses, but is not limited to, the following content:

- A discussion of the environmental requirements that the company currently faces and may realistically face in the future, with particular attention to an assessment of potential mandatory constraints on carbon dioxide emissions using different caps, costs of carbon and allowance allocation assumptions. Relevant assumptions used in this assessment, such as, but not limited to, the stringency of targets, trading, and the price of carbon credits, will be included with the findings.
- An assessment of the actions the company is taking and realistic, strategic options the company could consider in responding to current and future requirements. This process will take into account the impacts on shareholder value and the competitive position of the company.

The Company will provide preliminary findings to the shareholder group no later than 10 days before the filing deadline for resolution submission to the 2006 proxy. A final report will be made public on or before March 31, 2006. The Company reserves the right to develop a stand-alone report or to incorporate this information in its annual environmental report and will consider the shareholder group's comments in making the

[illegible]
[illegible]

[illegible]
[illegible]

report presentation decision. The Company intends to use internal staff for this project, but may use external resources if needed. The report will be overseen by the Operations, Environmental, Health & Safety Issues Committee of the Progress Energy Board of Directors.

If the above proposal is satisfactory, please signify your acceptance in the space provided and return two originals to us at your earliest convenience. Please don't hesitate to contact me if you have any questions. We look forward to working with you on this endeavor.

Sincerely,

John R. McArthur

Accepted on behalf of the Brethren Benefit Trust by:

Dawn Wolfe 2-22-05

Dawn Wolfe, Boston Common Asset Management — Date

Accepted on behalf of the Office of the Comptroller of New York City by:

2/26/05

Patrick Doherty, The City of New York — Date



BOSTON COMMON
ASSET MANAGEMENT, LLC

December 12, 2005

Mr. John R. McArthur
Senior Vice President – Progress Energy Service Company,
General Counsel and Corporate Secretary
Progress Energy, Inc.
410 S. Wilmington Street
Raleigh, NC 27601-1748

Dear Mr. McArthur:

Thank you for meeting our shareholder group at Progress Energy headquarters on November 21, 2005 to discuss our company's efforts to address climate change. We were impressed by the coordination of the day's events and the opportunity to meet such a large number of Progress Energy staff from a variety of functional areas. Lively discussions, presentations from a varied group of skilled staff and the guided tour of Roxboro together formed a highly educational and worthwhile visit for our shareholder group. We would also like to congratulate you and your team on our Company's impressive safety record. We commend your performance and continued dedication to this critical area.

When our shareholder group first corresponded with Progress Energy one year ago, we expressed our deep interest in how our company is responding to the multiple risks and opportunities global climate change presents to electric power companies. With regulation to address greenhouse gas (GHG) emissions emerging at global and regional levels, we continue to seek assurance our Company is positioned to respond more effectively than its peers. Preparation of the climate risk report for stakeholders is an important indication of Progress' commitment to this issue. In advance of the Environmental Health and Safety Committee's presentation to the Board of Directors on the state of the Climate Risk Report, we present the following concerns and suggestions for your consideration. Our suggestions focus mainly on Policy and Model Design & Report Structure.

Internal and External Policy:

- *Include specific reference to climate change in the Progress Energy Environmental Policy.* Under the section on minimizing impacts we would consider a positive addition to be "take appropriate measure to prevent environmental degradation *and reduce emissions of carbon dioxide as part of our efforts to manage climate risk.*" Expressly including climate change in the policy underscores its relevance and importance to the company.

Boston Common Asset Management, LLC 84 State Street, Suite 1000, Boston MA 02109 Tel: (617) 720-5557 Fax: (617) 720-5665 www.bostoncommonasset.com

- *Include language on the need for a mandatory, federal level solution to climate risk that is implementable at the regional level.* At our Annual General Meeting in May 2005 Progress Energy CEO Bob McGehee stated a "need to address global warming at the national level." We encourage report authors to reinforce an expansion of this statement in the Climate Risk Report.
- *Actively promote the "technological revolution" you have identified as the answer.* Progress Energy asserts that policy must drive a "technological revolution" to address climate change. As a result we believe it is imperative the report demonstrate what our Company is doing to support this necessary technological revolution. This could include a much expanded discussion in the report on the use of renewables (specifically methane capture) and ICGG plants with carbon sequestration.
- *Encourage policy development to improve DSM programs among electricity producers.* Demand side management capable of reducing long term demand, as opposed to just occasionally "shaving the peak", has been implemented successfully in a number of states including California, Vermont, and Massachusetts. Effective DSM programs are driven by policies that include incentives beneficial to energy producers, such as reimbursements for reducing electricity demand in certain areas. We believe this can help reduce the need for new generation and still enable the company to secure revenue. A number of useful reports on this topic can be found at http://www.energy.ca.gov/commission/commissioners/rosenfeld.html, including *Extreme Efficiency, Lessons From California* published in February, 2005. We would encourage you to contact Art Rosenfeld, California Energy Commissioner, as part of your external expert survey.

Model Design & Report Structure:

- *All assumptions built into the model should be clearly defined.* For example, specifications on the type of coal plants being added in the model should provide the information necessary for more in-depth analysis of emissions. Details about exisiting and new generation should be clear.
- *Revisit gas cost assumption.* We feel it is important for report users to understand exactly where the switch takes place between base-load choices. Also, various gas price assumptions in line with current prices, and expectations for higher/lower prices should be used to ensure the report's relevance. We understand that gas price is significant variable, so detailing a current, high and low price would help maintain the models relevance.
- *Include a discussion of specific actions taken by Progress Energy in anticipation of emissions restrictions.* The *Inventory of Actions Annex* was a very useful tool in the American Electric Power climate report, allowing the reader to easily identify the company's actions that supported its words.
- *Technology advancements in base-load coal production should not be ignored in the model, especially for the sole purpose of positioning nuclear as the only solution.* For example, bringing a coal plant on-line with carbon sequestration capability would make the coal projection in the model in line with the nuclear projection. This would also reinforce Progress' commitment to technology based solutions.

In addition to the above suggestions, we are interested in further discussing our concerns regarding our Company's aggressive pursuit of nuclear powered base load generation. While nuclear can be considered a piece of the answer to addressing climate change, it is not the only answer. Doubling the capacity of the world's 441 nuclear plants is not capable of achieving 450 parts per million and it does little to encourage a technological revolution in the sector, as it does not directly support numerous creative solutions being discussed in this space. We hope this course is not being pursued without full consideration of other options.

We appreciate your consideration of our suggestions and we look forward to reviewing a more complete draft in advance of the report release in March 2006. Thank you again for organizing such an educational and productive trip to Raleigh for our shareholder group. We look forward to future dialogue on this important topic.

Sincerely,

Dan Bakal, Director of Electric Power Programs, CERES
Millicent Budhai, Bureau of Asset Management, The City of New York Office of the Comptroller
Patrick Doherty, Bureau of Asset Management, The City of New York Office of the Comptroller
Steven Heim, Director of Social Research
Will Thomas, Director of Foundation Operations, Brethren Benefit Trust, Inc
Dawn Wolfe, Social Research and Advocacy Analyst

APPENDIX 4
Report Oversight & Process

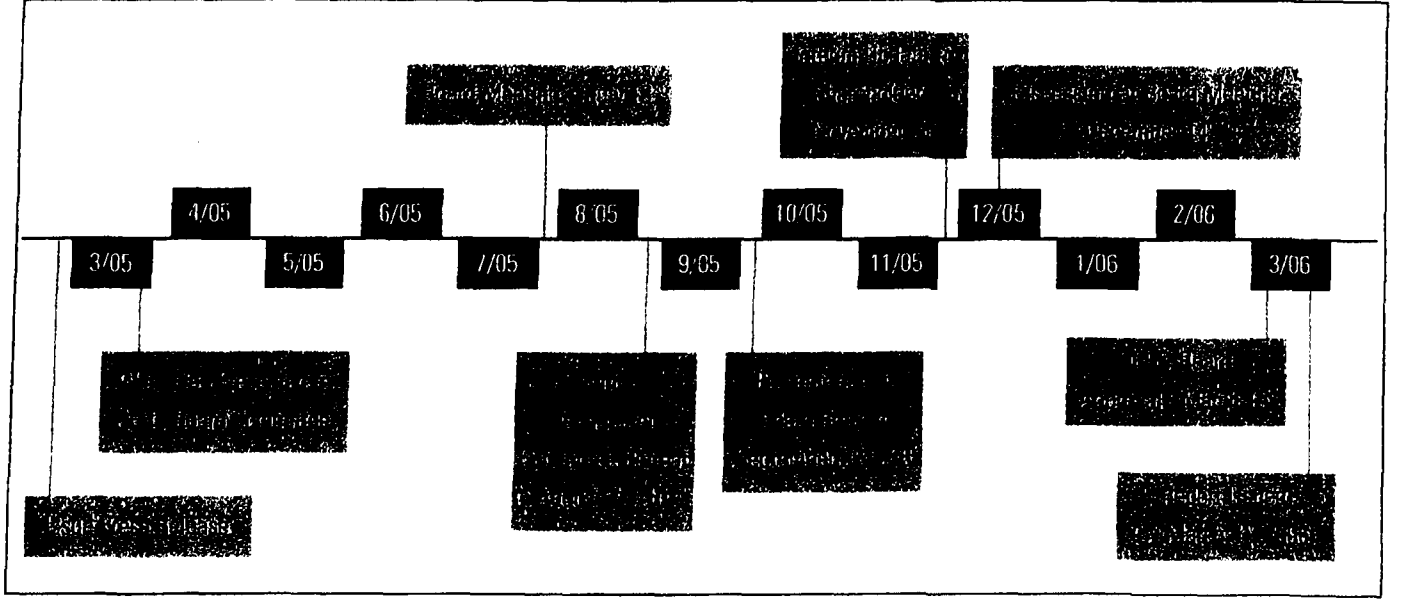
Progress Energy's board of directors, specifically its Operations, Environmental, Health & Safety Issues (OEHS) Committee, oversaw the preparation of this report and reviewed its contents. Members of the committee are:

- Edwin B. Borden – retired president, The Borden Manufacturing Co. (textile management services), Goldsboro, N.C.
- James E. Bostic Jr. – retired executive vice president, Georgia-Pacific Corp. (manufacturer and distributor of tissue paper, pulp, packaging, building products and related chemicals), Atlanta, Ga.
- Richard L. Daugherty – formerly executive director, NCSU Research Corp., vice president, IBM PC Company, and senior state executive, IBM Corp., Raleigh, N.C.
- W.D. "Bill" Frederick Jr. – citrus grower and rancher, formerly mayor of Orlando, and partner in the law firm of Holland & Knight, Orlando, Fla.
- E. Marie McKee – senior vice president, Corning, Inc. (developer of technologies for glass, ceramics, fiber optics and photonics) and president and chief executive officer, Steuben Glass, Corning, N.Y.
- Peter S. Rummell – chairman and CEO, The St. Joe Company (a real estate operating company), Jacksonville, Fla.
- Jean Giles Wittner – president, Wittner & Co., Inc. and subsidiaries (real estate management and insurance brokerage and consulting), St. Petersburg, Fla.

In addition, Progress Energy's senior management team also reviewed the contents of this report, including:

- Robert B. McGehee – chairman and chief executive officer
- William D. Johnson – president and chief operating officer
- Don K. Davis – executive vice president, Diversified Operations
- Peter M. Scott III – president and chief executive officer, Progress Energy Service Company, and chief financial officer, Progress Energy
- H. William Habermeyer Jr. – president and chief executive officer, Progress Energy Florida
- Fred N. Day IV – president and chief executive officer, Progress Energy Carolinas
- C.S. Hinnant – senior vice president and chief nuclear officer
- Jeffrey J. Lyash – senior vice president, Progress Energy Florida
- John R. McArthur – senior vice president, Corporate Relations, and General Counsel
- Mark F. Mulhern – president, Progress Energy Ventures
- E. Michael Williams – senior vice president, Power Operations, and chairman, Environment, Health & Safety Performance Council
- Lloyd M. Yates – senior vice president, Progress Energy Carolinas

The timeline below shows the major milestones in the report's preparation.



070007-Hearing Exhibit 000450

A large team of Progress Energy employees contributed to the development of this report, including: Len Anthony, Nancy Balcom-Moskalik, Bruce Barkley, Bob Bazemore, Grant Blume, Ed Brewer, Greg Cagle, Caroline Choi, Lisa Cooper, Byron Covey, Sally Dixon, Bob Drennan, Rob Drew, Don Ennis, Leigh Ann Frink, David Gammon, Kathy Hawkins, Mike Joyner, Dan Kemp, Mike Kennedy, Brad Lawson, Edward Lynch, Alan Madewell, John Masiello, Jeanelle McCain, John Moreci, Gerald Morgan, Pam Murphy, Bob Niekum, Joe Pietrzak, Wade Pridgen, Michael Reid, David Roberts, Mike Shrader, Paula Sims, Paul Snead, Capricia Townes, David Tsai, Cheryl Vetter, Sam Waters, Patty West, Mitch Williams, Katie Woodruff and Dana Yeganian.

In addition, Progress Energy also consulted many outside experts about their thoughts on the issue of global climate change and what steps the company could take to address this issue, including:

- Gerry Stokes – director, Joint Global Change Research Institute, University of Maryland
- Michael Shore – Southeast air quality manager, Environmental Defense
- Dallas Bertraw – senior fellow, Resources for the Future
- David Conover – principal deputy assistant secretary, U.S. Department of Energy
- John Shanahan – majority counsel, U.S. Senate Environment and Public Works Committee
- Mark Menezes – chief counsel, U.S. House Energy and Commerce Committee
- Margaret Caravelli – counsel, U.S. House Energy and Commerce Committee

The company also contacted other organizations and individuals to discuss the issue, but they were unable to participate in interviews.

Finally, the company greatly appreciates the insight and feedback from the shareholders who requested this report and the organizations they represent.

- Dan Bakal – director of electric power programs, CERES
- Millicent Budhai – Bureau of Asset Management, The City of New York Office of the Comptroller
- Patrick Doherty – Bureau of Asset Management, The City of New York Office of the Comptroller
- Steven Heim, director of social research, Boston Common Asset Management
- Will Thomas, director of foundation operations, Brethren Benefit Trust, Inc.
- Dawn Wolfe, social research and advocacy analyst, Boston Common Asset Management

070007-Hearing Exhibit 000451

APPENDIX 5
Glossary/Acronyms

Baseload generation: Those generating facilities within a utility system that are operated to the greatest extent possible to maximize system mechanical and thermal efficiency and minimize system operating costs. Units or plants are designed for nearly continuous operations at or near full capacity.

Biomass: A variety of organic fuel sources, such as animal or agricultural waste, which can be either processed into synthetic fuels or burned directly to produce steam or electricity.

Btu: British thermal unit. The standard unit for measuring quantity of heat energy, such as the heat content of fuel. It is the amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit.

Busbar costs: Generally synonymous with generating costs. Includes all costs from the end of the radial circuit that connects the generator to the utility transmission or distribution network.

CAIR: Clean Air Interstate Rule. See Appendix 1 for details.

CAMR: Clean Air Mercury Rule. See Appendix 1 for details.

CAVR: Clean Air Visibility Rule. See Appendix 1 for details.

Carbon dioxide (CO_2): A colorless, odorless, nonpoisonous gas normally part of ambient air. Fossil fuel combustion produces significant quantities of carbon dioxide.

Carbon sequestration: The capture and storage of carbon dioxide and other greenhouse gases that would otherwise be emitted to the atmosphere. The greenhouse gases can be captured at the point of emission, or they can be removed from the air. The captured gases can be stored in underground reservoirs, dissolved in deep oceans, converted to rock-like solid materials, or contained in trees, grasses, soils or algae.

Clean coal technology: Any of the methods developed, or being researched, to reduce emissions of various pollutants as a result of burning coal. These technologies primarily have concentrated on reducing emissions of sulfur dioxide and/or nitrogen oxide, and may also attempt to reduce carbon dioxide or mercury. Examples of clean coal technologies include various forms of: fluidized bed combustion, advanced coal cleaning, sorbent injection, low-NOx burners, catalytic removal, and alternative fuels (such as coal slurry mixtures, coal gasification or liquefaction).

Clean Smokestacks Act: A North Carolina law that requires reductions in sulfur dioxide and nitrogen oxide emissions from the state's coal-fired power plants. See Appendix 1 for more details.

Coal fines: Coal with a particle size that is usually less than one-sixteenth inch and rarely above one-eighth inch.

Combined cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Combustion turbine: An electric generating unit in which the prime mover is a gas turbine engine, similar to a jet engine.

Demand side management (DSM): The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand.

DENR: North Carolina Department of Environment and Natural Resources.

EMS: Environmental Management System.

Existing resources: The sum of the seasonal unit ratings for both systems.

FDEP: Florida Department of Environmental Protection.

070007-Hearing Exhibit 000452

Federal Energy Regulatory Commission (FERC): An independent agency created through the Department of Energy Organization Act on October 1, 1977. The Commission regulates the transmission and wholesale sales of electricity in interstate commerce, including:

- Approving rates, terms and conditions for wholesale electric sales of electricity and transmission in interstate commerce for investor-owned electric utilities, power marketers, power pools and independent system operators/regional transmission operators (RTOs).
- Overseeing the issuance of certain stock and debt securities, assumption of obligations and liabilities, and mergers.
- Reviewing the holding of officer and director positions between top officials in utilities and certain other firms they do business with.
- Conferring exempt wholesale generator status under the Energy Policy Act.
- Certifying qualifying small power production and cogeneration facilities that use energy for both the production of electricity and in an industrial or commercial process.

FERC does not approve the physical siting of electrical generation, transmission or distribution facilities. FERC also does not regulate the activities of government-owned power systems, the Tennessee Valley Authority, the Bonneville Power Authority, and most rural electric cooperatives. FERC does license and inspect hydroelectric projects and administers accounting and financial reporting regulations and conduct of jurisdictional companies.

Firm demand: Sum of total retail and wholesale demand, plus losses, less the impact of interruptible loads.

Firm demand plus reserve requirements: For Progress Energy Carolinas (PEC), this equals firm demand plus approximately 12 percent to 15 percent. PEC uses a range rather than a fixed number. In Florida, this is the Firm Demand plus a 20 percent reserve requirement, as prescribed by an agreement with the Florida Public Service Commission.

Fluidized bed combustion: A technique whereby air is injected through the bottom of a furnace so that coal and a sulfur absorbing material, such as limestone or dolomite, are buoyed and mixed during combustion. This technique removes 90 percent or more of the sulfur dioxide from emissions and also significantly reduces nitrogen oxide emissions.

Fuel cell: A system that converts the chemical energy of a fuel directly to direct current electricity without intermediate combustion or thermal cycles.

FPSC: Florida Public Service Commission.

Greenhouse gases (GHG): The natural and anthropogenic gaseous constituents of the atmosphere that help retain solar radiation by preventing its dissipation into space. The primary greenhouse gases in the atmosphere are water (H_2O), carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4). Other greenhouse gases include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride.

Hydrogen fuel cell: As the most abundant element in the universe, hydrogen has potential as an alternative source of energy. Specifically, hydrogen gas can be stripped from substances such as water or natural gas and used in a hydrogen fuel cell to make electricity.

Integrated Gasification Combined Cycle (IGCC): An electric generating technology where coal, water and oxygen are fed to a gasifier, which produces a medium-Btu gas, called syngas. Particulates and sulfur compounds are removed from the syngas, which is then fed to a gas turbine. The exhaust from the gas turbine and heat recovered from the gasification process are routed through a heat-recovery steam generator to produce steam, which drives a steam turbine to produce electricity.

Intermediate generation: The range from baseload to a point between baseload and peak. This point may be the midpoint, a percent of the peak load, or the load over a specified time period.

Kilowatt (kW): One kilowatt equals 1,000 watts.

Kilowatthour (kWh): The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatthour equals 1,000 watthours.

Megawatt (MW): One megawatt equals one million watts.

Megawatthour (MWh): One megawatthour equals one million watthours.

NCUC: North Carolina Utilities Commission.

New resources required: Capacity required to make up any difference between the sum of Existing Capacity and Purchases, and the Firm Demand plus Reserve Requirements.

070007-Hearing Exhibit 000453

Nitrogen oxides (NOx): Gases formed in great part from atmospheric nitrogen and oxygen when combustion takes place under conditions of high temperature and high pressure; considered a major air pollutant.

Nuclear Regulatory Commission (NRC): The mission of the NRC is to regulate the nation's civilian use of byproduct, source and special nuclear materials to ensure adequate protection of public health and safety, to promote the common defense and security, and to protect the environment. The NRC's scope of responsibilities includes regulation of nuclear power plants; research, test and training reactors; fuel cycle facilities; medical, academic and industrial uses of nuclear materials; and the transport, storage and disposal of nuclear materials and wastes.

Peaking generation: A generating unit available to assist in meeting that portion of peak load that is above baseload. These units are usually low-efficiency, quick response steam units, gas turbines, diesels or pumped-storage hydroelectric equipment. Peakers are characterized by quick start times and generally high operating costs, but low capital costs.

Power uprate: The process of increasing the maximum power level at which a commercial nuclear power plant may operate.

Purchases: Contracts to purchase power, including contracts with cogenerators and purchases from other utilities and suppliers.

Renewable energy: Any source of energy that is continually available or that can be renewed or replaced. Examples include wind, solar, geothermal, hydroelectric, photovoltaic, wood, waste and biomass. Nonrenewable energy sources include coal, oil and gas, which all exist in finite amounts.

Renewable Portfolio Standard (RPS): A mandate, or goal, set to require or promote the use of renewable resources for electric generation. The standard generally states that a certain percentage of a retail electric providers overall or new generating capacity or energy sales must be derived from renewable resources, with the percentage increasing gradually over time. An RPS most commonly refers to electric sales measured in megawatthours, as opposed to electricity capacity measured in megawatts.

SCPSC: South Carolina Public Service Commission.

SCR (Selective Catalytic Reduction): A method to reduce nitrogen oxide in which exhaust gases produced by a coal-fired electric generating unit pass through the SCR, where an ammonia or a urea solution reacts with the nitrogen oxide in the exhaust and converts it to nitrogen and water, prior to the exhaust going up the smokestack. An SCR works in a manner similar to a car's catalytic converter.

Scrubber (Flue Gas Desulfurization Unit): A device that uses a liquid spray to remove aerosol and gaseous pollutants from an air stream. The gases are removed either by absorption or chemical reaction. Solid and liquid particulates are removed through contact with the spray.

Solar photovoltaic: A cell that converts sunlight into electrical energy and is used as a power source.

Solar thermal: Systems using concentrating collectors to focus the sun's radiant energy onto or into receivers to produce heat.

Sulfur dioxide (SO_2): A colorless gas of compounds of sulfur and oxygen that is produced primarily by the combustion of fossil fuel.

Supercritical coal plant: Coal plants which use a much higher pressure steam and temperature during the combustion process, producing fewer emissions.

Synthetic fuel: Fuel formed by combining coal and coal fines with a chemical change agent. Formation of chemical bonds between the coal fines and the binding agent results in a chemical change in the product.

Watt: The electrical unit of real power or rate of doing work.

Watthour: The total amount of energy used in one hour by a device that requires one watt of power for continuous operation. Electric energy is commonly sold by the kilowatthour.

Sources: Edison Electric Institute, Nuclear Regulatory Commission, Progress Energy, U.S. Energy Information Administration, U.S. Environmental Protection Agency

070007-Hearing Exhibit 000454

Progress Energy Florida's Responses to

Deposition Transcript of West 10/19/07

070007

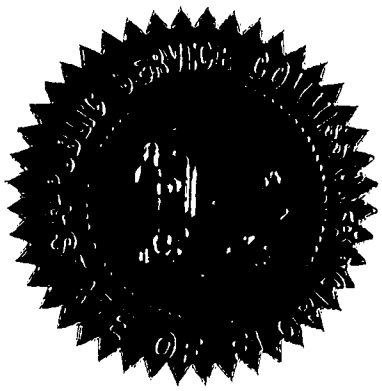
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070007-EI

In the Matter of

ENVIRONMENTAL COST RECOVERY CLAUSE.

_____/



ELECTRONIC VERSIONS OF THIS TRANSCRIPT ARE
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THE .PDF VERSION INCLUDES PREFILED TESTIMONY.

TELEPHONIC DEPOSITION OF:	PATRICIA Q. WEST
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Room 382D Gerald L. Gunter Building 2540 Shumard Oak Boulevard Tallahassee, Florida
TIME:	Commenced at 2:10 p.m. Concluded at 2:29 p.m.
DATE:	Friday, October 19, 2007
REPORTED BY:	LINDA BOLES, RPR, CRR Official FPSC Reporter (850) 413-6734

070007-Hearing Exhibit 000456

APPEARANCES:

GARY V. PERKO, ESQUIRE, Hopping Law Firm, Post Office Box 6526, Tallahassee, Florida 32314, appearing (via telephone) on behalf of Progress Energy Florida, Inc.

JOHN W. MCWHIRTER, JR., ESQUIRE, c/o McWhirter Law Firm, 400 North Tampa Street, Suite 2450, Tampa, Florida 33602, appearing (via telephone) on behalf of Florida Industrial Power Users Group.

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

070007-Hearing Exhibit 000457

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070007-Hearing Exhibit 000458

EXHIBITS

NUMBER:		ID.
1	FPL Notice of Suspension of Phase II Rules	15
2	TECO Notice of Suspension of Phase II Rules	15

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S T I P U L A T I O N

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

070007-Hearing Exhibit 000460

D E P O S I T I O N

MS. BROWN: Okay. This is the deposition of Patricia Q. West in Docket Number 070007-EI. And would the notary please swear in the witness?

PATRICIA Q. WEST

was called as a witness and, after being duly sworn by the notary present with the witness, testified as follows:

MS. BROWN: All right. Thank you. Now if I might mention to the notary that if she would fax me the affidavit to this number, we can have it attached to the deposition. It's (850) 413-6188. Will that be satisfactory?

THE NOTARY: That's fine. I believe I have -- do I have the acknowledgment?

MS. BROWN: You should. It should have been attached -- it was attached to the notice of deposition.

THE NOTARY: Thank you.

MS. BROWN: All right. Shall we get started?

BY MS. BROWN:

Q Ms. West, would you please state your name for the record?

MR. PERKO: Martha, did you want to get appearances first?

MS. BROWN: Oh, sure. This is Martha Carter Brown on behalf of the staff.

MR. PERKO: This is Gary Perko of Hopping, Green &

070007-Hearing Exhibit 000461

Sams on behalf of Progress Energy Florida.

MS. BROWN: All right. Thank you.

BY MS. BROWN:

Q Now, Ms. West, would you state your name for the record?

MR. McWHIRTER: Do you want to put my name in too?

MS. BROWN: Oh, geez. You guys have to bear with me. I'm rusty.

No, John, we don't want your name.

(Laughter.)

Please go ahead.

MR. McWHIRTER: John McWhirter representing the Florida Industrial Power Users Group.

MS. BROWN: All right. Anyone else? All right. Now we'll get started.

BY MS. BROWN:

Q Ms. West, will you state your name for the record?

A Patricia Quest West.

Q And by whom are you employed and in what capacity?

A I'm employed by Progress Energy Florida as the Manager of Environmental Services for the Power Operations Group.

Q All right. It's my understanding you filed direct testimony in all three segments of this docket: The true-up, estimated/actual and projections testimony; correct?

070007-Hearing Exhibit 000462

A Yes.

Q Do you have any changes to make to that testimony or to any of your exhibits?

A No.

Q Okay. The subject matter that we want to pursue today, I think you've been told, is in connection with the Phase II Cooling Water Intake Project, your Comprehensive Demonstration Study under 316B of the Phase II rules, and the area that we want to discuss concerns what actions you undertook to comply with that Cooling Water Intake Project. To get started, could you generally describe that project and the study Progress undertook in connection with it?

A Yes. If you'd refer to Phase II of the -- 316(b) of the Clean Water Act. We began work on that project back in 2004 looking at each of the studies, each of the facilities that were affected by that rule. Those sites included our Suwannee Plant, Crystal River, Bartow and Anclote. We established, as required by the Department of Environmental Protection, proposals for information collection, and those plans were approved by DEP. And then we implemented biological studies that looked at environmental, potential environmental effects of the power plants on the aquatic environments surrounding each of those facilities. Those studies began in 2005 at varying points in time depending upon the permit and the requirements that were issued to us by DEP, and we've

070007-Hearing Exhibit 000463

concluded all of those studies with the exception of our Crystal River facility. And those biological studies will be completed in December of this year.

Q All right. As I understand your testimony, Progress has determined that it will not, that it will not complete the Comprehensive Demonstration Study because EPA has indicated that the Phase II rules have been suspended. But am I correct in that assumption?

A We're not going to complete the CDS as originally anticipated as it was prescribed by the rule. We do plan to complete all of the biological studies at the facilities, we plan to complete statistical data analysis of those facilities as a result of the biological studies, as well as consider whether or not adverse environmental impacts are being, are happening at any of those facilities. And if they, it is determined that there are adverse environmental impacts, we will point back to our proposal for information collection and look at a high level at remediation or mitigation technologies that may be able to bring us into compliance with the target areas that were identified by the Phase II rule and are also being looked at by, currently being looked at by DEP as they look at moving forward with 316(b) in the future.

Q So what are you not completing?

A We are not completing a comprehensive evaluation of the control technologies, if you will. As the CDS was

070007-Hearing Exhibit 000464

originally contemplated, we would have completed the Comprehensive Demonstration Study, biological studies and data analysis and then done a very intense technological evaluation looking at engineering and design options at each of the facilities.

Q Oh, I see.

A That would have been prescribed by the Phase II rule.

Q Okay. FP&L and TECO have indicated in their notices to the Commission filed in this docket -- I think you have copies of those with you, don't you?

A Yes.

Q They've indicated that they intend to continue with their studies. We're interested in knowing why Progress has intended not to continue. And can you explain why you decided it was appropriate to stop at this point?

A Well, what I would like to clarify is that we're not necessarily stopping. I reviewed all of the testimony. In the context where we talked about ceasing work, it was ceasing the originally anticipated scope of the CDS. We have been in close communication with TECO and FP&L through the FCG and independently, as well as DEP, and I believe that we are in step with the other utilities. Our plan and intention for our facilities is the same as FP&L and TECO.

Q So to just clarify, the portions of your proposed study that remain to be completed are the, the very detailed

070007-Hearing Exhibit 000465

engineering analysis designed to determine how to correct any, any anticipated problems with aquatic life around the plants; is that right?

A That is true. That is true.

Q Okay. So let's, let's get to some questions about the costs that PEF has incurred up to this point and how much PEF would expect it would cost to complete the remainder of the study.

So what were the total costs incurred by PEF before they determined to stop the study?

A In which year?

MR. PERKO: Martha, I just -- I don't mean to be argumentative, but I just object because I'm not sure the testimony indicates that she's -- that Progress has stopped the study. I think she's explained that.

BY MS. BROWN:

Q Okay. Well, let's see. For all applicable years what were the total costs that Progress has incurred up to this point when it determined that it would delay any further high level or detailed investigation pending some changes in the, in the suspension of the Phase II rules?

A What I do have in front of me, Martha, is the year 2007.

Q Okay.

A You know, what we had originally anticipated, and

070007-Hearing Exhibit 000466

then in consideration of the suspension and our slowdown, if you will, in work as we worked with DEP to clarify their expectations and the guidance they were being issued by EPA. And I do show that our expected expenditures for 2007, including the time for the suspension, is about $477,000.

Q Right. And that's considerably less than you projected last year; correct?

A Yes, it is.

Q To the tune of about $900,000?

A Yes.

Q Okay. So this you expect to expend in 2007. You said you were going to conclude all of the studies you intend to do by December '07, December 2007.

A We will have concluded all of our biological studies by the end of 2007. Into 2008 we will continue our statistical analysis of that data, and also concurrent or in the same time frame begin looking at the high level technological evaluation.

Q And what are your, the projections of the cost for those activities?

A I believe it's $147,500 for 2008.

Q And would that be it until it becomes more clear what's going to happen with the Phase II rules?

A At this time that's what I would say, yes.

Q Okay. Now if PEF had completed the study and done the more detailed evaluations, would that have satisfied your

070007-Hearing Exhibit 000467

obligations under the Phase II rules? Would there have been anything more that you would have needed to do? I'm, I'm trying to get at what benefits PEF may have foregone by, by concluding its study at this level.

A I don't believe we've foregone any benefit. What we have done is by continuing the work rather than stopping it with the suspension is we've taken advantage of all of our mobilization and costs, and the fact that we were halfway through some of the studies, as well as continuing to do the data analysis while it's still fresh in everyone's mind. So I don't see us having foregone any benefit. In fact, I think it would be of a longer term benefit that we have this, this evaluation completed and prepared for discussion with DEP as we look forward to their suspending their rule and working toward new rulemaking efforts at the EPA.

Q When that happens, what steps do you anticipate Progress will have to take to, to begin this evaluation again? Will you have to start from scratch or will you be able to use the information from the studies that you have already compiled?

A I believe that we can use the data that we have collected. And that's been confirmed in our recent discussions with DEP, that they have given us the direction to continue those studies, compile the statistical analysis and continue with our high level technological review.

070007-Hearing Exhibit 000468

Q All right.

A So based on their guidance, yes, I believe it will be of benefit.

Q All right. Give us a minute or two and then I think we can wrap up. Actually give us 30 seconds.

(Pause.)

Ms. West, I think we're almost done. We have one follow-up question about the $900,000 that Progress is, is not going to spend this year in light of the Phase II suspension.

Can you tell us what, what that $900,000 comprises? What's involved in it? What does it represent?

A Well, it represents some time that we did not proceed with the statistical analysis, as well as increasing our engineering and design effort. It was going to be -- most of that money was targeted toward engineering and design evaluation and effort.

MS. BROWN: All right. I think that's all the questions we have.

Gary, do you have any follow-up?

MR. PERKO: Yeah. Just a couple to clarify.

CROSS EXAMINATION

BY MR. PERKO:

Q Ms. West, you mentioned that $900,000 that was not spent in 2006, I'm sorry, 2007 included some of the statistical analysis and the increased engineering associated with the

070007-Hearing Exhibit 000469

comprehensive -- what's the -- comprehensive design study?

A Demonstration.

Q Demonstration study or CDS. Now the statistical analysis that you referenced, it's my understanding that that will be a statistical analysis of the data from the biological studies that have been completed; correct?

A Yes.

Q So there will not be any need to redo any of those biological studies.

A True.

Q Okay. And you said you had FPL's submission before you?

A Yes, I do.

MR. PERKO: Martha, could we mark that as an exhibit?

MS. BROWN: Sure. Why don't we mark them both.

MR. PERKO: Okay. That's fine.

MS. BROWN: We'll identify them as deposition Exhibit 1, FPL's Notice of Suspension of Phase II Project, and Exhibit 2, TECO's Notice of Suspension of Phase II Project.

(Exhibits 1 and 2 marked for identification.)

BY MR. PERKO:

Q And, Ms. West, if I could refer you to Exhibit Number 1, which is the FPL notice that Ms. Brown just mentioned.

A Yes.

070007-Hearing Exhibit 000470

Q On Page 2, Paragraph 10, if you could look at the final sentence of that paragraph, which I'll just read. It states that, "FPL believes that the following activities should continue and that FPL should continue to recover the costs for those activities via the ECRC." And then there are two bullets, the first of which says, "Complete sampling events for all facilities and complete data summary reports." And the second bullet says, "Conduct 'high level' evaluations of potential technologies (including cooling towers) that could be used to reduce impingement mortality and entrainment at FPL facilities."

You mentioned the work that you will be completing as part of the Phase II rules or the suspended Phase II rules. Is that work consistent with the statement in the FPL notice that I just read to you?

A Yes, it is.

MR. PERKO: That's all I have.

MS. BROWN: Gary, I have one more follow-up, Ms. West, and then we'll be done.

REDIRECT EXAMINATION

BY MS. BROWN:

Q You mentioned that all the biological studies are going to be completed by the end of this year. How long have they been going on? Have they been -- have you been engaged in that for, for a full year or more?

070007-Hearing Exhibit 000471

A Yes.

MS. BROWN: Okay. Well, I have nothing further, so I think we can conclude. And thank you very much, Ms. West. Thank you, Gary, John.

MR. McWHIRTER: You're welcome.

MR. PERKO: Ms. West, you have the opportunity to read your deposition transcript to correct any typographical errors and such, and I would suggest you do that.

THE WITNESS: I will do that.

MR. PERKO: Okay. And, Martha, we'll get that errata sheet to you as soon as possible.

MS. BROWN: All right. And the, and the affidavit of the notary and then we'll be all set.

MR. PERKO: All right.

(Deposition concluded at 2:29 p.m.)

070007-Hearing Exhibit 000472

ERRATA SHEET
DO NOT WRITE ON TRANSCRIPT - ENTER CHANGES HERE

IN RE: DOCKET NO. 070007-EI
NAME: PATRICIA Q. WEST
DATE: October 19, 2007

PAGE	LINE	CHANGE

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

I, LINDA BOLES, CRR, RPR, Official FPSC Commission Reporter, do hereby certify that I was authorized to and did stenographically report the foregoing deposition at the time and place herein stated.

I FURTHER CERTIFY that this transcript, consisting of 17 pages, constitutes a true record of the testimony given by the witness.

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 October, 2007.

Linda Boles

LINDA BOLES, CRR, RPR
Official FPSC Hearings Reporter
850/413-6734

070007-Hearing Exhibit 000474

CERTIFICATE OF OATH

STATE OF Florida

COUNTY OF Pinellas

I, the undersigned authority, certify that Patria West personally appeared before me at Progress Energy Plaza and was duly sworn by me to tell the truth.

WITNESS my and official seal in the City of St. Petersburg, County of Pinellas, State of FL, this 19, day of October, 2007.

Notary Public

State of Florida

Personally known ✓ OR produced identification

April D. Harley
Commission # DD570482
Expires July 30, 2010
Bonded Troy Fain-Insurance, Inc. 800-385-7019

Type of identification produced _____.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause.	)	Docket No. 070007-EI Filed: April 13, 2007

NOTICE OF SUSPENSION OF PHASE II RULES ADOPTED PURSUANT TO CLEAN WATER ACT SECTION 316 (b)

Florida Power & Light Company ("FPL") hereby notifies the Commission and all parties of record that on March 20, 2007, the United States Environmental Protection Agency ("EPA") announced that the rule it adopted pursuant to Section 316(b) of the Clean Water Act to establish requirements for reducing the mortality of aquatic organisms by cooling water intake structures at certain existing large power plants (the "Phase II Rule")[1] should be considered suspended. A copy of EPA's March 20, 2007 letter is attached hereto as Exhibit 1. As explained in the letter, EPA intends to suspend the Phase II Rule based on the recent decision in *Riverkeeper, Inc. v. EPA*, 475 F.3d 83 (2nd Cir. 2007), which remanded several provisions of the Phase II Rule to EPA for further rulemaking. The letter states that EPA intends to issue a Federal Register notice formally suspending the Phase II Rule in the near future, but no such notice has been issued yet.

FPL recovers through the Environmental Cost Recovery Clause ("ECRC") costs associated with conducting the Comprehensive Demonstration Study ("CDS") that is required by the Phase II Rule. When the Commission approved FPL's "CWA 316(b) Phase II Rule" project, it observed that there was a possibility the Phase II Rule would be stayed and directed FPL to notify the Commission promptly of the stay. Order No. PSC-04-0987-PAA-EI, Docket No. 040582-EI, dated October 11, 2004. The Phase II Rule was never stayed, but because the effect

1 The Phase II Rules are codified in 40 CFR Parts 9, 122, 123, 124, and 125, and became effective on September 7, 2004.



of EPA's announced intention to suspend the Phase II Rule will be similar to the effect of a stay, FPL has elected to notify the Commission of EPA's intent.

Attached hereto as Exhibit 2 is the affidavit of Randall R. LaBauve, FPL's Vice President of Environmental Services. The affidavit explains that FPL is presently collecting biological data needed for the CDS. While FPL does not yet know the specific terms of EPA's suspension, it likely will render the current deadline for submitting a CDS ineffective. Therefore, strictly from a deadline perspective, FPL may have the option of suspending its data collection, as well as the data analysis and technology evaluation work that FPL plans to conduct in support of filing the CDS. However, for the reasons explained in the affidavit, FPL does not intend to suspend that work because it would not be cost-effective or appropriate to do so. FPL believes that the costs of the work remain ECRC recoverable, because the work will continue to be useful for purposes related to the Phase II Rule, irrespective of the ultimate outcome of EPA's further rulemaking.

Respectfully submitted,

R. Wade Litchfield, Esq.
Associate General Counsel
John T. Butler, Esq.
Senior Attorney
Law Department
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408-0420
Telephone: 561-304-5639
Fax: 561-691-7135

By: /s/ John T. Butler
John T. Butler
Florida Bar No. 283479

CERTIFICATE OF SERVICE
Docket No. 070007-EI

I HEREBY CERTIFY that a true and correct copy of Florida Power & Light Company's Notice of Suspension of Phase II Rules Adopted Pursuant to Clean Water Act Section 316(b) has been furnished by electronic delivery this 13th day of April, 2007 to the following:

Martha Brown, Esq.
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

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Pensacola, Florida 32576-2950

By: /s/ John T. Butler
John T. Butler

070007-Hearing Exhibit 000478

EXHIBIT 2

AFFIDAVIT

STATE OF FLORIDA
COUNTY OF PALM BEACH

BEFORE ME, the undersigned authority, personally appeared Randall R. LaBauve, who being first duly sworn deposes and says:

1. My name is Randall R. LaBauve, and I occupy the position of Vice President of Environmental Services, Florida Power & Light Company ("FPL"), 700 Universe Boulevard, Juno, Florida. In this position I have knowledge of and have familiarity with the matters addressed in this affidavit.

2. I received a Bachelor of Arts degree in Psychology from Louisiana State University in 1983 and a Juris Doctor degree from Louisiana State University in 1986. I joined FPL in 1995 as an Environmental Lawyer and in 1996 assumed the responsibility of Director of Environmental Services. In July of 2002, I assumed the responsibility of Vice President of Environmental Services. Prior to joining FPL, I was the Director of Environmental Affairs for Entergy Services, Incorporated located in Little Rock, Arkansas and prior to that practiced law with Milling, Benson, Woodward, Hilliard, Pierson and Miller in New Orleans, Louisiana.

3. I am responsible for directing the overall corporate environmental planning, programs, licensing, and permitting activities to ensure the basic objective of obtaining and maintaining the federal, state, regional and local government approvals necessary to site, construct and operate FPL's power plants, transmission lines, and fuel facilities and maintain compliance with environmental laws.

4. On June 21, 2004, FPL petitioned for cost recovery through the Environmental Cost Recovery Clause ("ECRC"), for the costs associated with performing a Comprehensive Demonstration Study ("CDS") to determine the effect of its cooling water intake structures on aquatic life. FPL's petition stated that the CDS was necessary to address rules adopted by the U.S. Environmental Protection Agency ("EPA") pursuant to Section 316(b) of the Clean Water Act (the Phase II Rule"). The Phase II Rule established requirements to reduce the mortality of aquatic organisms by cooling water intake structures at certain existing large power plants. The Phase II rule was codified in 40 CFR Parts 9, 122, 123, 124, and 125, effective date September 7, 2004, but it was subsequently challenged by several environmental groups and six northeastern states.

5. On October 11, 2004, the Florida Public Service Commission issued Order No. PSC-04-0987-PAA-EI in Docket No. 040582-EI authorizing FPL to recover prudently incurred CDS costs through the ECRC. The Order noted that it was possible the Phase II Rule would be stayed; that there was no stay at the time of the Order; but that, "If a stay is issued, FPL shall file a copy of it with the Commission within two weeks of its issuance. The manner in which the stay will be handled procedurally and substantively will be addressed at the time."

6. The Phase II Rule was never stayed, and FPL has continued to gather data and perform analyses necessary for the CDS, which was essential in view of the CDS deadline established by the rule.

7. On January 25, 2007, the Second Circuit Court of Appeals issued its decision on the rule challenges in *Riverkeeper, Inc. v. EPA*, which resulted in a remand of the Phase II Rule to EPA on several grounds.

8. On March 20, 2007, Benjamin Grumbles, the Assistant Administrator of the EPA, issued a memorandum entitled "Implementation of the Decision in *Riverkeeper, Inc. v. EPA*, Remanding the Cooling Water Intake Structures Phase II Regulation" (the "EPA Memorandum"). The EPA Memorandum states that, "With so many provisions of the Phase II rule affected by the decision, the rule should be considered suspended. I anticipate issuing a Federal Register notice formally suspending the rule in the near future. In the meantime, all permits for Phase II facilities should include conditions under section 316(b) of the Clean Water Act developed on a Best Professional

Judgment (BPJ) basis. See 40 C.F.R. Section 401.14." To date, no Federal Register notice has been issued on this subject. A copy of the EPA Memorandum is attached hereto as Exhibit 1.

9. Because the effect of EPA's intended suspension of the Phase II Rule will be similar to the effect of a stay, FPL has elected to notify the Commission of EPA's intent.

10. While FPL does not yet know the specific terms of EPA's suspension, it is likely to render the current deadline for submitting a CDS ineffective. Therefore, strictly from a deadline perspective, FPL may have the option of suspending the data collection and analysis activities that it has been performing in support of filing a CDS. However, FPL does not believe that it would be cost-effective or appropriate to suspend that work. FPL has completed biological sampling at one facility and is near completion (by mid-May) at three of the remaining six facilities. The Cape Canaveral Plant and the St. Lucie Plant have several months of sampling remaining. FPL believes that the following activities should continue and that FPL should continue to recover the costs for those activities via the ECRC:

    - Complete sampling events for all facilities and complete data summary reports.
    - Conduct "high level" evaluations of potential technologies (including cooling towers) that could be used to reduce impingement mortality and entrainment at FPL facilities.

11. These foregoing activities should continue to completion for the following reasons:

    - To be meaningful, biological sampling must occur in a minimum of one-year intervals so all seasons are represented. To discontinue sampling with only partial-year data would invalidate, or certainly make much less valuable, all of the data previously collected. Moreover, to restart a sampling program would result in a minimum of $50,000 in incremental mobilization fees for each facility.
    - It would be much more efficient to have the data that is currently being collected analyzed and summarized now, rather than putting the data "on the shelf" and then analyzing it later. Important details about the data collection could be lost in the interim, and the analytical personnel would not be as familiar with the data if significant time passes between data collection and analysis.
    - For similar reasons, the high level technology evaluations based on the data should be performed contemporaneously.

12. FPL expects that the foregoing biological data collection and analysis, and the high level technology evaluations, will continue to be highly useful to FPL, no matter the eventual outcome of rulemaking on the Phase II Rule.

    - The EPA Memorandum indicates that EPA will require BPJ determinations pursuant to the NPDES permit process while the Phase II Rule is suspended. This means that FPL will have to address its plans to reduce the mortality of aquatic organisms in cooling water intake structures as part of its NPDES permit renewal applications via the BPJ process during the suspension period. FPL will be required to demonstrate to the Florida Department of Environmental Protection (FDEP") permit writers that the operation of each permitted facility has no "adverse environmental impact." The current data collection and analysis will assist the FDEP permit writers in determining the impact of the permitted facility's cooling water intake structures, and the technology evaluation will assist them in determining the proper course of action for the facility to take.

    - Future rulemaking proceedings on the Phase II Rule – Rulemaking that was conducted for the existing Phase II Rule was based on biological data that were generally 30 years old. Technology evaluations that were made to determine the overall cost of the rule, as well as potential costs to an individual facility were based on minimal data submitted to EPA in a 1998 questionnaire. Having more detailed technology/cost data will assist FPL in presenting

070007-Hearing Exhibit 000481

its views on the true cost of the revised rule and enable FPL to better justify the inclusion of realistic, cost-effective compliance alternatives in the revised rule.

- Given the nature of the issues on which the Phase II Rule was remanded by the 2nd Circuit, it is highly likely that a CDS or something comparable will be required under the revised Phase II Rule. FPL's biological data and analysis, as well as its high level technology evaluation, would be useful to support FPL's compliance with such requirements in the revised rules.

- Some or all of the grounds for remand in *Riverkeeper, Inc. v. EPA* could be reversed in subsequent appellate review by the Second Circuit *en banc*, or by the Supreme Court if certiorari is sought and granted.

13. Regardless of the status of the Phase II Rule, FPL continues to be subject to a "governmentally imposed environmental regulation enacted after the utility's last test year upon which rates are based" -- as contemplated by section 366.8255 of the Florida Statutes and Order No. PSC-94-0044-FOF-EI -- to address the entrainment and impingement of marine organisms at its power plants. That requirement arises either under the Phase II Rule or, in the absence of currently effective rules, as part of the NPDES permitting process pursuant to section 316(b) of the Clean Water Act. As noted above, FPL expects that if the Phase II Rule is not effective at the time of the next round of NPDES permitting, FPL will be required to make a similar showing about entrainment and impingement of marine organisms at its power plants to what the Phase II Rule would have required. That showing would become the basis for the FDEP's BPJ determination, which is an integral part of the NPDES permit renewal process.

14. FPL projects that completing the current biological data collection and analysis, and performing high level technology evaluations based on that analysis, will cost approximately $2 million. FPL expects that these expenses all will be incurred in 2007and 2008.

15. Affiant says nothing further.

Randall R. LaBauve

SWORN TO AND SUBSCRIBED before me this 13th day of April 2007, by Randall R. LaBauve, who is personally known to me or who has produced _____ (type of identification) as identification and who did take an oath.

Notary Public, State of Florida

My Commission Expires:

Notary Public State of Florida
Jacqueline S Bussey
My Commission DD575498
Expires 07/18/2010

070007-Hearing Exhibit 000482

ORIGINAL

AUSLEY & MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

227 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

April 17, 2007

HAND DELIVERED

Ms. Ann Cole
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

FILED
07 APR 17 PM 3:51
COMMISSION
CLERK

Re: Environmental Cost Recovery Clause
FPSC Docket No. 070007-EI

Dear Ms. Cole:

Enclosed for filing in the above docket are the original and fifteen (15) copies of Tampa Electric Company's Notice of Suspension of Phase II Rules Adopted Pursuant to Clean Water Act Section 316(b).

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosure

cc: All Parties of Record (w/enc.)
Mr. Jim Breman (w/enc.)

RECEIVED & FILED

FPSC-BUREAU OF RECORDS

DOCUMENT NUMBER-DATE
03278 APR 17 07
FPSC-COMMISSION CLERK

070007-Hearing Exhibit 000483

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause.	)	DOCKET NO. 070007-EI
	)	FILED: April 17, 2007

TAMPA ELECTRIC COMPANY'S
NOTICE OF SUSPENSION OF PHASE II RULES
ADOPTED PURSUANT TO CLEAN WATER ACT SECTION 316(B)

Tampa Electric Company ("Tampa Electric" or "the company") hereby notifies the Commission and all parties of record that on March 20, 2007, the United States Environmental Protection Agency ("EPA") announced that the rule it adopted pursuant to Section 316(b) of the Clean Water Act to establish requirements for reducing the mortality of aquatic organisms by cooling water intake structures at certain existing large power plants (the "Phase II Rule")[1] should be considered suspended. A copy of EPA's March 20, 2007 letter is attached hereto as Exhibit 1. As explained in the letter, EPA intends to suspend the Phase II Rule based on the recent decision in *Riverkeeper, Inc. v. EPA*, 475 F.3d 83 (2nd Cir. 2007), which remanded several provisions of the Phase II Rule to EPA for further rulemaking. The letter states that EPA intends to issue a Federal Register notice formally suspending the Phase II Rule in the near future, but no such notice has been issued yet.

Tampa Electric recovers through the Environmental Cost Recovery Clause ("ECRC") costs associated with conducting the Comprehensive Demonstration Study ("CDS") that is required by the Phase II Rule. When the Commission approved Tampa Electric's "CWA 316(b) Phase II Rule" project, it observed that there was a possibility that Phase II Rule would be stayed and directed Tampa Electric to notify the Commission promptly of the stay. Order No. PSC-05-0164-PAA-EI,

[1] The Phase II Rules are codified in 40 CFR Parts 9, 122, 123, 124 and 125, and became effective on September 7, 2004.



DOCUMENT NUMBER-DATE
03278 APR 17 8
FPSC-COMMISSION CLERK
070007-Hearing Exhibit 000484

Docket No. 041300-EI, dated February 10, 2005. The Phase II Rule was never stayed, but because the effect of EPA's announced intention to suspend the phase II Rule will be similar to the effect of a stay, Tampa Electric has elected to notify the Commission of EPA's intent.

Attached hereto as Exhibit 2 is the affidavit of Laura R. Crouch, Tampa Electric's Manager – Land and Water Programs in the Environmental Health and Safety Department. The affidavit explains that Tampa Electric is presently collecting biological data needed for the CDS. While Tampa Electric does not yet know the specific terms of EPA's suspension, it likely will render the current deadline for submitting a CDS ineffective. Therefore, strictly from a deadline perspective, Tampa Electric may have the option of suspending its data collection, as well as the data analysis and technology evaluation work that Tampa Electric plans to conduct in support of filing the CDS. However, for the reasons explained in the affidavit, Tampa Electric does not intend to suspend that work because it would not be cost-effective or appropriate to do so. Tampa Electric believes that the costs of the work remain ECRC recoverable, because the work will continue to be useful for purposes related to the Phase II Rule, irrespective of the ultimate outcome of EPA's further rulemaking.

DATED this 17th day of April 2007.

Respectfully submitted,

LEE L. WILLIS
JAMES D. BEASLEY
Ausley & McMullen
Post Office Box 391
Tallahassee, FL 32302
(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

070007-Hearing Exhibit 000485

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Notice of Suspension of Phase II Rules Adopted Pursuant to Clean Water Act Section 316(b), filing on behalf of Tampa Electric Company, has been furnished by U. S. Mail or hand delivery (*) on this 17th day of April 2007 to the following:

Ms. Martha Carter Brown*
Office of General Counsel
Florida Public Service Commission
Room 370N – Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Mr. Charles Beck
Ms. Patricia Christensen
Office of Public Counsel
111 West Madison Street – Suite 812
Tallahassee, FL 32399-1400

Mr. John W. McWhirter, Jr.
McWhirter, Reeves & Davidson, P.A.
400 North Tampa Street, Suite 2450
Tampa, FL 33601-5126

Mr. John T. Butler
Senior Attorney
Florida Power & Light Company
700 Universe Boulevard
June Beach, FL 33408-0420

Mr. R. Wade Litchfield
Ms. Natalie F. Smith
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420

Mr. Gary V. Perko
Ms. Carolyn S. Raepple
Ms. Virginia C. Dailey
Hopping Green & Sams, P.A.
Post Office Box 6526
Tallahassee, FL 32314

Mr. R. Alexander Glenn
Deputy General Counsel - Florida
Mr. John T. Burnett
Associate General Counsel - Florida
Progress Energy Service Co., LLC
Post Office Box 14042
St. Petersburg, FL 33733

Ms. Susan Ritenour
Gulf Power Company
One Energy Place
Pensacola, FL 32520

Mr. Jeffrey A. Stone
Mr. Russell A. Badders
Mr. Steven R. Griffin
Beggs and Lane
Post Office Box 12950
Pensacola, FL 32591-2950

ATTORNEY

070007-Hearing Exhibit 000486

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAR 20 2007

MEMORANDUM

OFFICE OF WATER

SUBJECT: Implementation of the Decision in *Riverkeeper, Inc. v. EPA*, Remanding the Cooling Water Intake Structures Phase II Regulation

FROM: Benjamin Grumbles, Assistant Administrator

TO: Regional Administrators

The purpose of this memorandum is to provide guidance on the status of the Cooling Water Intake Structures Phase II regulation under section 316(b) of the Clean Water Act ("Phase II rule" or "Rule"). The Phase II rule set national standards for cooling water withdrawals by large, existing power producing facilities ("Phase II facilities"). See 40 C.F.R. Part 125 Subpart J; 69 Fed. Reg. 41576 (July 6, 2004).The Second U.S. Circuit Court of Appeals recently issued its decision in the litigation over the Phase II regulation. See Riverkeeper, Inc., v. EPA, No. 04-6692, (2d Cir. Jan. 25, 2007).

The court's decision remanded several provisions of the Rule on various grounds. The provisions remanded include:

- EPA's determination of the Best Technology Available under section 316(b);
- The Rule's performance standard ranges;
- The cost-cost and cost-benefit compliance alternatives;
- The Technology Installation and Operation Plan provision;
- The restoration provisions; and
- The "independent supplier" provision.

With so many provisions of the Phase II rule affected by the decision, the rule should be considered suspended. I anticipate issuing a Federal Register notice formally suspending the Rule in the near future.[1] In the meantime, all permits for Phase II facilities should include conditions under section 316(b) of the Clean Water Act developed on a Best Professional Judgment basis. See 40 C.F.R. § 401.14.

If you have questions regarding the application of section 316(b) at Phase II facilities, please contact either Janet Goodwin with the Office of Science and Technology at 202-566-1060 (goodwin.janet@epa.gov) or Deborah Nagle with the Office of Wastewater Management at 202-564-1185 (nagle.deborah@epa.gov).

[1] In the event that the court's decision is overturned prior to publication of the Federal Register notice, then I will not proceed to effect the suspension; if the court's decision is overturned after publication of the notice, the Agency will take appropriate action in response.

AFFIDAVIT

STATE OF FLORIDA
COUNTY OF HILLSBOROUGH

BEFORE ME, the undersigned authority, personally appeared Laura R. Crouch, who being first duly sworn deposes and says:

1. My name is Laura R. Crouch, and I serve as the Manager - Land and Water Programs in the Environmental, Health and Safety Department of Tampa Electric Company ("Tampa Electric"), 702 North Franklin Street, Tampa, Florida 33602. In this position I have knowledge of and familiarity with the matters addressed in this Affidavit.

2. I received a Bachelors Degree in Chemical Engineering from the University of South Florida. I began my career at Tampa Electric in 1995 as an engineer in Environmental Planning with responsibility for air and chemical management related activities. In 1997, I joined Regulatory Affairs with responsibility for rate analyses, preparing for regulatory proceedings and assisting in rate design for retail special contracts. In 1999, I worked in the Resource Planning department with responsibility for providing engineering support towards the company's integrated resource planning process and business planning activities. In 2001, I was promoted to Manager – Air Programs in the Environmental, Health and Safety Department. In that position, I was responsible for all air permitting and compliance programs. In 2005, I became Manager, Land and Water Programs and my present responsibilities include the management of land and water permitting and compliance.

3. I am responsible for directing the overall corporate environmental planning, programs, licensing and permitting activities to ensure Tampa Electric's achievement of the basic objective of obtaining and maintaining the federal, state, regional and local government approvals necessary to site, construct and operate Tampa Electric's power plants, transmission lines and fuel facilities and maintaining compliance with environmental laws.

4. On November 10, 2004, Tampa Electric petitioned for cost recovery through the Environmental Cost Recovery Clause ("ECRC") the costs associated with performing a Comprehensive Demonstration Study ("CDS") to determine the effect of its cooling water intake structures on aquatic life. Tampa Electric's petition stated that the CDS was necessary to address rules adopted by the U. S. Environmental Protection Agency ("EPA") pursuant to Section 316(b) of the Clean Water Act ("the Phase II Rule"). The Phase II Rule establishes performance standards that are designed to reduce impingement and entrainment of aquatic organisms related to the withdrawal of waters of the United States for cooling purposes through cooling water intake structures. The Phase II Rule was codified in 40 CFR Parts 9, 122, 123, 124 and 125, effective September 7, 2004, but it was subsequently challenged by several environmental groups and six northeastern states.

5. On February 10, 2005, the Florida Public Service Commission (the "Commission") issued Order No. PSC-05-0164-PAA-EI in Docket No. 041300-EI proposing agency action authorizing Tampa Electric to recover prudently incurred CDS costs through the ECRC. The Order noted that it was possible that the Phase II Rule would be stayed. The Order noted that the rule is in effect, but it is impossible to know whether it will be stayed or changed in a way that affects Tampa Electric's CDS activity. Accordingly, the Order further provided that if the EPA rule is stayed or new content is proposed, Tampa Electric shall notify the Commission within two weeks of such change. That proposed agency action decision became final with the issuance of Commission Order No. PSC-05-0254-CO-EI on March 7, 2005.

6. The Phase II Rule was never stayed, and Tampa Electric has continued to gather data and perform analyses necessary for the CDS, which was essential in view of the CDS deadline established by the rule.

7. On January 25, 2007, the Second Circuit Court of Appeals issued its decision on the rule challenges in *Riverkeeper, Inc. v. EPA*, which resulted in a remand of the Phase II Rule to EPA on several grounds.

8. On March 20, 2007, Benjamin Grumbles, the Assistant Administrator of the EPA, issued a memorandum entitled "Implementation of the Decision in *Riverkeeper, Inc. v. EPA*, Remanding the Cooling Water Intake Structures Phase II Regulation" (the "EPA Memorandum"). The EPA Memorandum states that, "With so many provisions of the Phase II rule affected by decision, the rule should be considered suspended. I anticipate issuing a Federal Register notice formally suspending the rule in the near future. In the meantime, all permits for Phase II facilities should include conditions under section 316(b) of the Clean Water Act developed on a Best Professional Judgment (BPJ) basis. See 40 C.F.R. Section 401.14." To date, no Federal Register notice has been issued on this subject. A copy of the EPA Memorandum is attached herein as Exhibit 1.

9. Because the effect of EPA's intended suspension of the Phase II Rule will be similar to the effect of a stay, Tampa Electric has elected to notify the Commission of EPA's intent.

10. While Tampa Electric does not yet know the specific terms of EPA's suspension, it is likely to render the current deadline for submitting a CDS ineffective. Therefore, strictly from a deadline perspective, Tampa Electric may have the option of suspending the data collection and analysis activities that it has been performing in support of filing a CDS. However, Tampa Electric does not believe that it would be cost-effective or appropriate to suspend that work. Tampa Electric completed biological sampling at the Bayside Power Station in March 2007. All other costs for Bayside will be incurred due to report preparation and biological data evaluation, projected to be completed in September 2007. As a result of the imminent suspension of Phase II Rule, the biological data collection at the Big Bend Power Station has been revised to focus on key aspects of the study. The Big Bend Power Station biological sampling, based on a revised biological sampling plan, will be completed by October 2007. All other costs will be incurred due to report

preparation and data evaluation, projected to be complete in January 2008 Tampa Electric believes that the following activities should continue and that Tampa Electric should continue to recover the costs for those activities via the ECRC:

- Complete sampling events for all facilities and complete data report preparation.

11. These foregoing activities should continue to completion for the following reasons:

- To be meaningful, biological sampling must occur in a minimum of one-year intervals so all seasons are represented. To discontinue sampling with only partial-year data would invalidate, or certainly make much less valuable, all of the data previously collected. Moreover, to restart a sampling program would result in a minimum of $50,000 in incremental mobilization fees for each facility.

- It would be much more efficient to have the data that is currently being collected analyzed and summarized now, rather than putting the data "on the shelf" and then analyzing it later. Important details about the data collection could be lost in the interim, and the analytical personnel would not be as familiar with the data if significant time passes between data collection and analysis.

12. Tampa Electric expects that the foregoing biological data collection and analysis will continue to be highly useful to Tampa Electric, no matter the eventual outcome of rulemaking on the Phase II Rule.

- The EPA Memorandum indicates that EPA will require BPJ determinations pursuant to the National Pollutant Discharge Elimination System ("NPDES") permit process while the Phase II Rule is suspended. This means Tampa Electric will have to address its plans to reduce the mortality of aquatic organisms in cooling water intake structures as part of its NPDES permit renewal applications via the BPJ process during the suspension period. Tampa Electric will be required to demonstrate to the Florida Department of Environmental Protection ("FDEP") permit writers that the operation of each permitted facility has no "adverse environmental impact." The current data collection and analysis will assist the FDEP permit writers in determining the impact of the permitted facility's cooling water intake structures, and the technology evaluation will assist them in determining the proper course of action for the facility to take.

- Completion of on-going biological data collection and analysis will support compliance with future rulemaking proceedings on the Phase II Rule. Rulemaking that was conducted for the existing Phase II Rule was based on biological data that were generally 30 years old. Technology evaluations that were made to determine the overall cost of the rule, as well as potential costs to an individual facility were based on minimal data submitted to EPA in a 1998 questionnaire. Having more detailed technology/cost data will assist Tampa Electric in presenting its views on the true cost of the revised rule and enable

070007-Hearing Exhibit 000490

Tampa Electric to better justify the inclusion of realistic, cost-effective compliance alternatives in the revised rule.

- Given the nature of the issues on which the Phase II Rule was remanded by the 2nd Circuit, it is highly likely that a CDS or something comparable will be required under the revised Phase II Rule. Tampa Electric's biological data and analysis would be useful to support Tampa Electric's compliance with such requirements in the revised rules.

- Some or all of the grounds for remand in *Riverkeeper, Inc. v. EPA* could be reversed in subsequent appellate review by the Second Circuit *en banc* or by the Supreme Court if certiorari is sought and granted.

13. Regardless of the status of the Phase II Rule, Tampa Electric continues to be subject to a "governmentally imposed environmental regulation enacted after the utility's last test year upon which rates are based" - - as contemplated by section 366.8255 of the Florida Statutes and Order No. PSC-94-0044-FOF-EI - - to address the entrainment and impingement of marine organisms at its power plants. That requirement arises either under the Phase II Rule or, in the absence of currently effective rules, as part of the NPDES permitting process pursuant to section 316(b) of the Clean Water Act. As noted above, Tampa Electric expects that if the Phase II Rule is not effective at the time of the next round of NPDES permitting, Tampa Electric will be required to make a similar showing about entrainment and impingement of marine organisms at its power plants to what the Phase II Rule would have required. That showing would become the basis for the FDEP's BPJ determination, which is an integral part of the NPDES permit renewal process.

14. Tampa Electric projects that completing the current biological data collection, analysis and report preparation for the Bayside and Big Bend Power Stations will cost approximately $400,000. Tampa Electric expects that these expenses all will be incurred in 2007 and early 2008.

15. Affiant says nothing further.

Laura R. Crouch

SWORN TO AND SUBSCRIBED to me this 17th day of April 2007, by Laura R. Crouch, who is personally known to me or who has produced personally known (type of identification) as identification and who did take an oath.

Paula K. Brown
Notary Public, State of Florida

My Commission Expires:

Paula K Brown
My Commission DD360650
Expires December 04 2008

Gulf Power Company's Responses to

Staff's 1st ROGS Nos. 1 - 17

070007

1. What are the specific 2008 capital expenditures, by CAIR/CAMR/CAVR projects, included in the $23.5 million in projected ECRC revenue requirements referenced in Schedule 5P, Page 26 of 51 on Exhibit A of its Petition filed August 31, 2007 in Docket No. 070007-EI?

ANSWER:

The CAIR/CAMR/CAVR capital projects that impact the 2008 revenue requirements include installing Activated Carbon Injection (ACI) at Plant Daniel on Unit 2, Low NO_X Burners at Plant Daniel on Units 1 and 2, Selective Non-Catalytic Reduction (SNCR) technologies at Plant Smith on Units 1 and 2, and mercury monitoring equipment. The capital expenditures for these projects are shown in the table below:

2008 Projected
CAIR/CAMR/CAVR Expenditures

PE No.	Project	Amount ($)
1095	Mercury Relative Accuracy Test Audit Equipment	500,000
1362	Scholz Unit 1 & 2 Mercury Monitors	558,000
1468	Smith Unit 1 SNCR	4,400,000
1469	Smith Unit 2 SNCR	4,400,000
1512	Daniel Unit 1 Mercury Monitoring	400,000
1513	Daniel Unit 2 Mercury Monitoring	400,000
1646	Smith Unit 1 Mercury Monitoring	638,000
1647	Smith Unit 2 Mercury Monitoring	636,000
1810	Daniel Unit 2 Activated Carbon Injection	7,379,000
1824	Daniel Unit 1 Low NO_x Burners	320,800
1826	Daniel Unit 2 Low NO_x Burners	3,890,000
	Total	$23,521,800

The total capital revenue requirements associated with the CAIR/CAMR/CAVR Compliance Program for 2008 is projected to be $5.5 million, as shown on Schedule 4P, page 26, of Ms. Martin's direct testimony.

2. What are the dates during which GULF plans to install ACI on Plant Daniel Units 1 and 2?

ANSWER:

An ACI system will be installed on Plant Daniel Unit 2 during 2008 and on Plant Daniel Unit 1 during 2009. Both systems will be placed in service by January 1, 2010.

3. How are the costs for the installation of ACI on Plant Daniel being shared with Mississippi Power?

ANSWER:

Capital and O&M costs for Plant Daniel Units 1 and 2 are shared equally between Gulf and Mississippi Power pursuant to the 50% undivided ownership interest in Plant Daniel Units 1 and 2.

4. How does the decision to rely upon ACI for mercury control at Plant Daniel 1 and 2 effect the allocations, shortfall with controls, and delta (benefits of controls) shown on Table 5.2-2, Page 31, submitted in GULF's March 30, 2007 Supplemental Petition Regarding CAIR/CAMR/CAVR for 2010 through 2018?

ANSWER:

Changes in control schedules do not impact allocations; therefore, the emission allocations projected in Table 5.2-2 are not affected by adding ACI at Plant Daniel. The emission projections shown in Table 5.2-2 of Gulf's March 2007 Environmental Compliance Plan assumed 13% native mercury capture at Daniel without controls, 45% mercury capture with the scrubber (online 2011), and 80% mercury capture with the scrubber and SCR combination (online in 2016 and 2017). The use of ACI at Daniel is assumed to get 60% mercury capture, which will reduce the shortfall with controls and increase the benefits of controls listed in Table 5.2-2 prior to the SCR and scrubber combinations coming in service. An update to the data found in Table 5.2-2 is provided below.

Gulf's CAIR, CAMR, and CAVR Compliance Plan
Plants Crist, Scholz, Smith, and Daniel
Mercury Emission Program

	Allocations (Ho... Ounces)	Shortfall without Controls	Shortfall with Controls (March 2007)	Shortfall with Controls (August 2007)	Delta (Benefit of Controls) March 2007	Delta (Benefit of Controls) August 2007	Controls Added (March 2007)	Controls Added (August 2007)
2010	5,997	4,606	2,111	753	2,495	3,853	Crist FGD	Crist FGD, Daniel ACI
2011	5,997	4,559	30	(661)	4,529	5,220	Daniel FGD, Crist 6 SCR	Crist 6 SCR
2012	4,871	5,012	393	(64)	4,619	5,076		
2013	4,871	5,443	540	69	4,903	5,374		Daniel FGD
2014	4,871	5,426	453	(11)	4,973	5,437		Daniel 1 SCR
2015	4,871	5,110	128	(1,005)	4,982	6,115		Daniel 2 SCR
2016	4,871	4,933	(520)	(1,056)	5,453	5,989	Daniel 1 SCR	
2017	4,871	4,985	(1,203)	(1,204)	6,188	6,189	Smith FGD, Daniel 2 SCR	Smith FGD
2018	2,338	8,146	610	610	7,536	7,536	Smith 2 Baghouse	Smith 2 Baghouse

Note: Emissions results sourced from 2007 Energy Budget.

5. Table 5.2-2, Page 31, submitted in GULF's March 30, 2007 Supplemental Petition, shows shortfalls of -1,203 up to +610 mercury allowances for 2010 through 2018. What is the basis for GULF's conclusion that it is cost effective to install ACI at Plant Daniel Units 1 and 2?

ANSWER:

The Clean Air Mercury Rule (CAMR) will introduce a mercury allowance trading market by 2010. However, to date, the mercury allowance market has yet to develop. Mercury allocations are not expected to be populated until early 2008. The expectation is that the market will not begin to develop until allocation accounts are populated. It is uncertain if a liquid market will develop based on the number of utility participants. Total dependence on this market for compliance would be very risky and potentially costly for Gulf Power and its customers. ACI provides a proven control technology that will reduce the mercury emissions out of Plant Daniel by 60%. The technology mitigates Gulf Power's reliance on a yet undeveloped allowance market for compliance. The impact of ACI at Daniel on the projected cost savings to the customer from retrofitting the units compared to retirement and replacement is a small percentage (discussed further in the response to Interrogatory No. 7) of the initial savings shown for Plant Daniel in Gulf's March 29, 2007, CAIR/CAMR/CAVR Compliance Plan.

6. What is GULF's quantification of the "associated risk" for the undeveloped market for mercury allowances referenced on Page 11 of Witness Jim Vick's August 31, 2007 Direct Testimony? Explain how this quantification was completed.

ANSWER:

The reference to "associated risk" in Mr. Vick's testimony reflects a qualitative comparison of implementing the relatively low cost of Activated Carbon Injection (ACI) to the risk of noncompliance given the as yet undeveloped market for mercury allowances.

7. What is the NPV savings associated with retrofitting Plant Daniel compared to retiring the units given Gulf's plan to add ACI?

ANSWER:

The total NPV savings with ACI added is $308.4 million for Plant Daniel Unit 1 (2006-2032) and $327.2 million for Plant Daniel Unit 2 (2006-2036). These values reflect 50% ownership of Plant Daniel Units 1 and 2 by Gulf Power.

8. What are the mercury allowance prices used to calculate the NPV savings associated with retrofitting Plant Daniel as discussed on Page 11 of Witness Vick's August 31, 2007 direct testimony?

ANSWER:

The NPV savings of retrofitting Daniel compared to the retirement and replacement of Daniel that was referenced in Mr. Vick's testimony compares the forecasted cost to continue to operate the retrofitted unit to the forecasted cost of retiring and replacing the unit. The mercury allowance prices are just one part of that analysis.

Southern Company's 2007 mercury forecast, considered confidential and proprietary information, is shown below in nominal dollars per ounce:

2010	2011	2012	2013	2014	2015	2016	2017	2018
[redacted]								

2019	2020	2021	2022	2023	2024	2025	2026
[redacted]							

9. What are GULF's annual sales/purchases of seasonal and annual SO_2 allowances for 2006, 2007, and 2008, GULF's annual balance of SO_2 allowances, and GULF's annual SO_2 allocations?

ANSWER:

There are no seasonal SO_2 allowance programs under the Clean Air Act. The sales/purchases, annual allocation, and annual balances for annual SO_2 allowances are shown in the table below.

	Net Sales/ Purchases	Annual Allocation	Year End Balance*
2006	15,000	56,709	147,527
2007	15,000	56,709	156,513**
2008	0	56,709	78,610**

*Balances shown are after reduction for allowances used.
**Balance includes 19,000 pre-2009 vintage allowances from the swap of 43,510 vintage year 2013 and 2014 allowances.

The above referenced allowances exclude Gulf's allowances associated with its ownership of Plant Scherer Unit 3.

10. What are GULF's 2006, 2007, and 2008 sales/purchases of seasonal and annual NO_x allowances, its annual balance of NO_x allowances, and annual NO_x allocations?

ANSWER:

Gulf has not participated in sales or purchases of seasonal and annual NO_x allowances to date. Gulf's Environmental Compliance Plan projects both a seasonal and annual NO_x allowance need beginning in 2009. Florida's proposed seasonal and annual CAIR NO_x allocations have not been approved by the Environmental Protection Agency (EPA) due to lawsuits challenging the Florida Department of Environmental Protection rule and allocation formulas.

	Net Sales/ Purchases	Annual Allocation	Year End Balance
2006	0	0	0
2007	0	0	0
2008	0	0	0

11. What is the average actual/expected price of allowances purchased and sold by GULF in 2006, 2007, and 2008?

ANSWER:

The average 2006 and 2007 actual/expected price of SO_2 allowances purchased by Gulf was $980/allowance and $950/allowance, respectively. Gulf has not projected to purchase any allowances during 2008.

12. What are the Plant Daniel retrofit schedule changes mentioned on Page 11 of Witness Vicks August 31, 2007 direct testimony?

ANSWER:

Plant Daniel Units 1 and 2 will be retrofitted with Activated Carbon Injection (ACI), Selective Catalytic Reduction (SCR) technology, and a Flue Gas Desulfurization (FGD) scrubber. Installation of ACI at Plant Daniel will allow Plant Daniel the opportunity to adjust the timing for the installation of the FGD and SCR technologies in order to optimize the mercury control co-benefits of these two control technologies. The in-service date of the scrubber has changed from 2011 to 2013. The in-service date of the Daniel Unit 1 SCR has been changed from 2016 to 2014. The in-service date of the Daniel Unit 2 SCR has been changed from 2017 to 2015.

13. What forward contracts and swaps of emission allowances does GULF currently include in its portfolio?

ANSWER:

Gulf has a forward contract to purchase 16,000 2009 vintage SO_2 allowances. The contract will be settled by June of 2009. Gulf also has a contract for the swap of 43,510 vintage year 2013 and 2014 allowances for 19,000 pre-2009 vintage year allowances. The reason for the approximate 2 for 1 swap is due to the 50% reduced value of post-2009 allowances as compared to pre-2009 allowances. Gulf is evaluating the market for possible purchases and swaps in 2008.

14. What actions has GULF taken to ensure that it is achieving competitive market pricing for O&M associated with Plant Crist Unit 7 SCR and Crist Units 4 through 6 SNCR described on Pages 13 and 14 of Witness Vick's August 31, 2007 direct testimony?

ANSWER:

Chemical suppliers for the Crist Unit 7 SCR and Crist Units 4 through 6 SNCRs are selected through a competitive bid process. The labor and materials expenses for SNCR and SCR projects are also competitively bid.

15. Reconcile GULF's projections of 2008 CAM precipitator upgrade expenditures ($9.6 million) as shown on Schedule 5P, Page 22 of 51 of Rhonda Martin's August 31, 2007 direct testimony with the estimated 2008 capital expenditure for CAM precipitator upgrades (4,300,000 +/- 30%) appearing in Gulf's July 16, 2007 Preliminary List of New Projects. Explain any unexpected increases in costs which may have occurred, including timing changes related to the completion of the Crist Unit 5 upgrade.

ANSWER:

The July 2007 estimate of capital expenditures for 2008 for CAM precipitator upgrades of $4.3 million was for the Plant Crist Unit 4 precipitator upgrade. Since that time, the Crist Unit 5 outage schedule has been changed from the fall of 2007 to the spring of 2008. Therefore, the majority of the projected spending for the Unit 5 precipitator project, $5.3 million, was subsequently moved from the fall of 2007 to the spring of 2008. In addition to these changes, the actual project bids Gulf received were approximately $1.5 million higher than expected due primarily to increases in contract labor. The Crist Units 4 and 5 precipitator upgrade projects were adjusted to reflect the increase in costs. These updates were reflected in Gulf's 2008 ECRC projection filing. Therefore, the $9.6 million of capital expenditures in 2008 for CAM precipitator upgrades includes $4.3 million for Crist Unit 4 and $5.3 million for Crist Unit 5.

17. If GULF has revised its estimated purchase of 2009 through 2017 SO_2 allowances as alluded to on Page 11 of Witness Vick's August 31, 2007, Direct Testimony compared to that which was requested in its Supplemental Petition filed March 29, 2007, provide an updated version of the Supplemental Petition's Table 5.2-1 to account for the changes.

ANSWER

Updated data from Table 5.2-1 is provided below:

Gulf's CAIR, CAMR, and CAVR Compliance Plan
Plants Crist, Scholz, Smith, and Daniel
SO_2 Emission Program

	Allocations (SO_2 Tons)	Shortfall without Controls	Shortfall with Controls (March 2007)	Shortfall with Controls (August 2007)	Delta (Benefit of Controls) March 2007	Delta (Benefit of Controls) August 2007	Controls Added (March 2007)	Controls Added (August 2007)
2009	56,710	43,650	43,650	43,650	0	0		
2010	28,070	58,553	13,378	13,578	45,175	44,975	Crist FGD	Crist FGD
2011	28,070	52,402	(1,309)	9,975	53,711	42,427	Daniel FGD	
2012	28,070	48,304	(10,296)	8,189	58,600	40,115		
2013	28,070	51,791	(10,205)	8,847	61,996	42,944		Daniel FGD
2014	28,070	51,774	(10,551)	(10,551)	62,325	62,325		
2015	19,633	57,958	(4,617)	(4,617)	62,575	62,575		
2016	19,633	56,395	(4,533)	(4,533)	60,928	60,928		
2017	19,633	56,380	(6,101)	(6,101)	62,481	62,481	Smith FGD	Smith FGD

Note: Emissions results sourced from 2007 Energy Budget.

Confidential Staff Composite Exhibit - 3	Florida Power & Light Company 1. FPL's Response to Staff 4th Set of Interrogatories, (pages 1, 6, 19-27) and No. 40.
	Progress Energy Florida 2. PEF's Response to Staff's 1st Set of Interrogatories, No. 5 (including Attachment 5) and No. 22. 3. PEF's Response to Staff 2nd Set of PODs, No. 2 (PEF Bate Stamp Pages 00001 to 00004) and No. 4 (PEF Bate Stamp Pages 02156 to 02160).

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI **EXHIBIT** 3
COMPANY FPSC Staff
WITNESS Staff Composite Exhibit - 3
DATE 11-06-07

APPENDIX I

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

JANUARY 2006 - DECEMBER 2006
FINAL TRUE-UP

KMD-1
DOCKET NO. 070007-EI
EXHIBIT_____
PAGES 1-53

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 4
COMPANY Florida Power & Light
WITNESS K.M. Dubin (KMD-1)
DATE 11-06-07

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up for the Period
January through December 2006

Line No.			
1	Over/(Under) Recovery for the Current Period (Form 42-2A Page 2 of 2, Line 5)	$14,322,506	
2	Interest Provision (Form 42-2A Page 2 of 2, Line 6)	$651,087	
3	Total		$14,973,593
4	Estimated/Actual Over/(Under) Recovery for the Same Period *	$12,790,874	
5	Interest Provision	618,870	
6	Total		$13,409,744
7	Net True-Up for the period		$1,563,849

* Per Order No. PSC-06-0972-FOF-EI issued November 22, 2006.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2006

Line No.		January	February	March	April	May	June
1	ECRC Revenues (net of Revenue Taxes)	$1,989,709	$1,809,496	$1,785,173	$1,893,427	$2,104,432	$2,387,120
2	True-up Provision (Order No. PSC-05-1251-FOF-EI)	410,274	410,274	410,274	410,274	410,274	410,274
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	2,399,983	2,219,770	2,195,447	2,303,701	2,514,706	2,797,394
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5A, Line 9)	480,322	298,263	(21,106)	(711,084)	(471,896)	29,858
	b - Capital Investment Projects (Form 42-7A, Line 9)	1,209,279	1,216,832	1,215,256	1,212,594	1,235,789	1,257,085
	c - Total Jurisdictional ECRC Costs	1,689,601	1,515,095	1,194,150	501,510	763,893	1,286,943
5	Over/(Under) Recovery (Line 3 - Line 4c)	710,382	704,675	1,001,297	1,802,191	1,750,813	1,510,451
6	Interest Provision (Form 42-3A, Line 10)	28,325	30,291	33,030	38,714	45,464	52,402
7	Prior Periods True-Up to be (Collected)/Refunded in 2006	4,923,287	5,251,720	5,576,412	6,200,465	7,631,096	9,017,099
	a - Deferred True-Up from 2005 (Form 42-1A, Line 7)	2,642,893	2,642,893	2,642,893	2,642,893	2,642,893	2,642,893
8	True-Up Collected /(Refunded) (See Line 2)	(410,274)	(410,274)	(410,274)	(410,274)	(410,274)	(410,274)
9	End of Period True-Up (Lines 5+6+7+7a+8)	7,894,613	8,219,305	8,843,358	10,273,989	11,659,992	12,812,571
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$7,894,613	$8,219,305	$8,843,358	$10,273,989	$11,659,992	$12,812,571

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2006

Line No.		July	August	September	October	November	December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$2,501,167	$2,522,677	$2,488,652	$2,340,917	$2,034,046	$1,964,815	$25,821,630
2	True-up Provision (Order No. PSC-05-1251-FOF-EI)	410,274	410,274	410,274	410,274	410,274	410,274	4,923,287
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	2,911,441	2,932,951	2,898,926	2,751,191	2,444,320	2,375,089	30,744,917
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5A, Line 9)	265,550	(91,903)	(160,116)	213,087	72,689	984,365	888,029
	b - Capital Investment Projects (Form 42-7A, Line 9)	1,277,129	1,304,173	1,327,851	1,365,467	1,412,590	1,500,337	15,534,382
	c - Total Jurisdictional ECRC Costs	1,542,679	1,212,270	1,167,735	1,578,554	1,485,279	2,484,702	16,422,411
5	Over/(Under) Recovery (Line 3 - Line 4c)	1,368,762	1,720,681	1,731,191	1,172,637	959,041	(109,613)	14,322,506
6	Interest Provision (Form 42-3A, Line 10)	58,982	64,158	69,608	74,484	77,613	78,016	651,087
7	Prior Periods True-Up to be (Collected)/Refunded in 2006	10,169,678	11,187,148	12,561,713	13,952,238	14,789,085	15,415,465	4,923,287
	a - Deferred True-Up from 2005 (Form 42-1A, Line 7)	2,642,893	2,642,893	2,642,893	2,642,893	2,642,893	2,642,893	2,642,893
8	True-Up Collected /(Refunded) (See Line 2)	(410,274)	(410,274)	(410,274)	(410,274)	(410,274)	(410,274)	(4,923,287)
9	End of Period True-Up (Lines 5+6+7+7a+8)	13,830,041	15,204,606	16,595,131	17,431,978	18,058,358	17,616,487	17,616,487
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	$13,830,041	$15,204,606	$16,595,131	$17,431,978	$18,058,358	$17,616,487	$17,616,487

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2006

Interest Provision (in Dollars)

Line No.		January	February	March	April	May	June
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$7,566,180	$7,894,613	$8,219,305	$8,843,358	$10,273,989	$11,659,992
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	7,866,288	8,189,014	8,810,328	10,235,275	11,614,528	12,760,169
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$15,432,468	$16,083,627	$17,029,633	$19,078,633	$21,888,517	$24,420,161
4	Average True-Up Amount (Line 3 x 1/2)	$7,716,234	$8,041,814	$8,514,817	$9,539,317	$10,944,259	$12,210,081
5	Interest Rate (First Day of Reporting Month)	4.30000%	4.51000%	4.53000%	4.78000%	4.96000%	5.01000%
6	Interest Rate (First Day of Subsequent Month)	4.51000%	4.53000%	4.78000%	4.96000%	5.01000%	5.29000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	8.81000%	9.04000%	9.31000%	9.74000%	9.97000%	10.30000%
8	Average Interest Rate (Line 7 x 1/2)	4.40500%	4.52000%	4.65500%	4.87000%	4.98500%	5.15000%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.36708%	0.37667%	0.38792%	0.40583%	0.41542%	0.42917%
10	Interest Provision for the Month (Line 4 x Line 9)	$28,325	$30,291	$33,030	$38,714	$45,464	$52,402

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2006

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)	$12,812,571	$13,830,041	$15,204,606	$16,595,131	$17,431,978	$18,058,358	$148,390,122
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	13,771,059	15,140,448	16,525,523	17,357,494	17,980,745	17,538,471	157,789,342
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$26,583,630	$28,970,489	$31,730,129	$33,952,625	$35,412,723	$35,596,829	$306,179,464
4	Average True-Up Amount (Line 3 x 1/2)	$13,291,815	$14,485,245	$15,865,065	$16,976,313	$17,706,362	$17,798,415	$153,089,732
5	Interest Rate (First Day of Reporting Month)	5.29000%	5.36000%	5.27000%	5.26000%	5.27000%	5.25000%	N/A
6	Interest Rate (First Day of Subsequent Month)	5.36000%	5.27000%	5.26000%	5.27000%	5.25000%	5.27000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.65000%	10.63000%	10.53000%	10.53000%	10.52000%	10.52000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	5.32500%	5.31500%	5.26500%	5.26500%	5.26000%	5.26000%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.44375%	0.44292%	0.43875%	0.43875%	0.43833%	0.43833%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$58,982	$64,158	$69,608	$74,484	$77,613	$78,016	$651,087

Form 42-4A

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
January 2006 - December 2006

Variance Report of O&M Activities
(in Dollars)

Line		(1) Actual	(2) Estimated Actual	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities				
1	Air Operating Permit Fees-O&M	$1,792,167	$1,917,287	($125,120)	-6.5%
3a	Continuous Emission Monitoring Systems-O&M	$712,106	$694,758	$17,348	2.5%
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	$1,448,228	$1,248,141	$200,087	16.0%
8a	Oil Spill Cleanup/Response Equipment-O&M	$199,902	$187,215	$12,687	6.8%
13	RCRA Corrective Action-O&M	$84,784	$100,000	($15,216)	-15.2%
14	NPDES Permit Fees-O&M	$120,400	$132,400	($12,000)	-9.1%
17a	Disposal of Noncontainerized Liquid Waste-O&M	$320,395	$380,338	($59,943)	-15.8%
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	$683,311	$961,990	($278,679)	-29.0%
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	$140,888	$183,032	($42,144)	-23.0%
19c	Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	($560,232)	($560,232)	$0	0.0%
NA	Amortization of Gains on Sales of Emissions Allowances	($8,897,090)	($8,836,425)	($60,665)	0.7%
22	Pipeline Integrity Management	$142,234	$389,631	($247,397)	-63.5%
23	SPCC-Spill Prevention, Control & Countermeasures	$457,838	$502,343	($44,505)	-8.9%
24	Manatee Reburn	$1,534	$210,000	($208,466)	-99.3%
25	Port Everglades ESP	$598,826	$723,774	($124,948)	-17.3%
26	UST Replacement/Removal	$491,625	$350,086	$141,539	40.4%
27	Lowest Quality Water Source	$276,408	$322,385	($45,977)	-14.3%
28	CWA 316(b) Phase II Rule	$1,559,242	$1,665,846	($106,604)	-6.4%
29	SCR Consumables	$219,632	$198,620	$21,012	10.6%
30	HBMP	$22,282	$15,410	$6,872	44.6%
31	CAIR Compliance	$1,053,928	$602,963	$450,965	74.8%
32	BART	$22,806	$50,609	($27,803)	-54.9%
2	Total O&M Activities	$891,214	$1,440,171	($548,957)	-38.1%
3	Recoverable Costs Allocated to Energy	($3,986,503)	($3,878,329)	($108,174)	2.8%
4a	Recoverable Costs Allocated to CP Demand	$4,474,522	$4,636,626	($162,104)	-3.5%
4b	Recoverable Costs Allocated to GCP Demand	$403,195	$681,874	($278,679)	-40.9%

Notes:
Column(1) is the 12-Month Totals on Form 42-5A
Column(2) is the approved projected amount in accordance with FPSC Order No. PSC-06-0972-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 Final True-up Amount for the Period
January 2006 - December 2006

O&M Activities
(in Dollars)

Line #	Project #	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	$ 142,189	$ 101,883	$ 140,189	$ 219,861	$ 162,309	$ 163,130	$929,561
3a	Continuous Emission Monitoring Systems-O&M	157,963	35,649	33,990	40,129	16,772	173,155	457,658
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	21,000	0	(71,164)	252,698	210,404	48,005	460,943
8a	Oil Spill Cleanup/Response Equipment-O&M	(1,360)	6,267	8,661	14,441	5,130	7,318	40,457
13	RCRA Corrective Action-O&M	809	2,048	0	2,000	0	0	4,857
14	NPDES Permit Fees-O&M	112,900	0	0	0	0	0	112,900
17a	Disposal of Noncontainerized Liquid Waste-O&M	2,145	0	9,737	38,245	5,622	0	55,749
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	26,481	42,268	87,438	54,023	16,093	80,478	306,781
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	16,160	43,177	55,170	15,918	22,217	1,590	154,232
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	(30,642)	(30,642)	(743,237)	(1,568,173)	(1,223,370)	(748,623)	(4,344,687)
21	St. Lucie Turtle Net							0
22	Pipeline Integrity Management	(22,950)	8,984	92,049	1,799	0	44,725	124,607
23	SPCC - Spill Prevention, Control & Countermeasures	(948)	41,268	21,675	32,669	60,487	22,481	177,632
24	Manatee Reburn	0	0	0	0	0	0	0
25	Pt. Everglades ESP Technology	33,796	20,675	29,949	37,006	69,695	34,390	225,511
26	UST Replacement/Removal	0	10,509	0	1,341	55,367	33,621	100,838
27	Lowest Quality Water Source	32,611	21,492	0	42,387	20,904	23,151	140,545
28	CWA 316(b) Phase II Rule	40,293	34,237	12,495	108,229	65,837	125,708	386,799
29	SCR Consumables	3,504	8,938	39,955	18,547	190	32,386	103,520
30	HBMP	0	0	1,341	1,341	1,341	1,341	5,364
31	CAIR Compliance	0	2,230	305,987	11,709	76,981	31,056	427,963
32	BART	0	0	0	0	1,523	1,974	3,497
2	Total of O&M Activities	$ 487,265	$ 302,297	$ (22,451)	$ (722,516)	$ (479,184)	$ 29,200	$ (405,389)
3	Recoverable Costs Allocated to Energy	$ 307,042	$ 146,526	$ (172,321)	$ (1,188,806)	$ (885,235)	$ (306,887)	$(2,099,681)
4a	Recoverable Costs Allocated to CP Demand	$ 177,085	$ 136,846	$ 85,775	$ 435,610	$ 413,301	$ 278,952	$ 1,527,569
4b	Recoverable Costs Allocated to GCP Demand	$ 3,138	$ 18,925	$ 64,095	$ 30,680	$ (7,250)	$ 57,135	$ 166,723
5	Retail Energy Jurisdictional Factor	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	
6a	Retail CP Demand Jurisdictional Factor	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$ 302,540	$ 144,377	$ (169,794)	$ (1,171,372)	$ (872,252)	$ (302,387)	$(2,068,888)
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 174,645	$ 134,961	$ 84,593	$ 429,608	$ 407,606	$ 275,109	$ 1,506,522
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 3,138	$ 18,925	$ 64,095	$ 30,680	$ (7,250)	$ 57,135	$ 166,723
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 480,323	$ 298,263	$ (21,106)	$ (711,084)	$ (471,896)	$ 29,857	$ (395,643)

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 Final True-up Amount for the Period
January 2006 - December 2006

O&M Activities
(in Dollars)

Line #	Project #	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	$ 161,607	$ 161,607	$ 161,607	$ 161,607	$ 108,089	$ 108,089	$862,606	$1,792,167			$1,792,167
3a	Continuous Emission Monitoring Systems-O&M	48,768	43,550	26,459	45,054	19,166	71,451	254,448	712,106			712,106
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	197,868	79,938	16,252	164,566	156,516	372,145	987,285	1,448,228	1,448,228		
8a	Oil Spill Cleanup/Response Equipment-O&M	7,523	8,448	14,977	23,367	65,315	39,815	159,445	199,902			199,902
13	RCRA Corrective Action-O&M	0	25,946	23,209	0	2,114	28,658	79,927	84,784	84,784		
14	NPDES Permit Fees-O&M	0	7,500	0	0	0	0	7,500	120,400	120,400		
17a	Disposal of Noncontainerized Liquid Waste-O&M	121,980	(250)	0	71,884	30,387	40,645	264,646	320,395			320,395
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	49,319	39,288	45,353	128,233	52,361	61,976	376,530	683,311		683,311	
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	0	1,726	0	(15,070)	0	0	(13,344)	140,888	130,050		10,838
19c	Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)	(560,232)	(258,569)	(280,116)	(21,547)
20	Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0	0	0		
NA	Amortization of Gains on Sales of Emissions Allowances	(845,283)	(741,424)	(741,424)	(741,424)	(741,424)	(741,424)	(4,552,403)	(8,897,090)			(8,897,090)
21	St. Lucie Turtle Net											
22	Pipeline Integrity Management	16,867	52	0	0	0	708	17,627	142,234	142,234		
23	SPCC - Spill Prevention, Control & Countermeasures	50,189	32,824	36,467	90,846	23,241	46,639	280,206	457,838	457,838		
24	Manatee Rebum	0	0	0	0	0	1,534	1,534	1,534			1,534
25	Pt. Everglades ESP Technology	46,192	51,638	52,501	90,262	49,608	83,114	373,315	598,826			598,826
26	UST Replacement/Removal	186,877	31,891	16,556	1,909	18,074	135,480	390,787	491,625	491,625		
27	Lowest Quality Water Source	23,299	23,454	23,742	22,095	0	43,273	135,863	276,408	276,408		
28	CWA 316(b) Phase II Rule	225,463	118,698	154,755	149,071	231,841	292,615	1,172,443	1,559,242	1,559,242		
29	SCR Consumables	16,450	19,187	15,406	23,283	27,647	14,139	116,112	219,632			219,632
30	HBMP	1,341	1,341	10,064	1,341	0	2,831	16,918	22,282	22,282		
31	CAIR Compliance	5,616	46,280	27,701	41,487	76,720	428,161	625,965	1,053,928			1,053,928
32	BART	1,113	1,213	0	2,517	0	14,466	19,309	22,806			22,806
2	Total of O&M Activities	$ 268,503	$ (93,779)	$ (163,061)	$ 214,342	$ 72,969	$ 997,629	$ 1,296,603	$ 891,214	$ 4,474,522	$ 403,195	$(3,986,503)
3	Recoverable Costs Allocated to Energy	$ (437,830)	$ (411,414)	$ (444,569)	$ (284,918)	$ (366,288)	$ 58,194	$(1,886,823)	$ (3,986,503)			
4a	Recoverable Costs Allocated to CP Demand	$ 680,357	$ 301,690	$ 259,498	$ 394,370	$ 410,239	$ 900,802	$ 2,946,954	$ 4,474,522			
4b	Recoverable Costs Allocated to GCP Demand	$ 25,976	$ 15,945	$ 22,010	$ 104,890	$ 29,018	$ 38,633	$ 236,472	$ 403,195			
5	Retail Energy Jurisdictional Factor	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%					
6a	Retail CP Demand Jurisdictional Factor	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	$ (431,409)	$ (405,380)	$ (438,049)	$ (280,739)	$ (360,916)	$ 57,341	$(1,859,152)	$ (3,928,040)			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 670,983	$ 297,533	$ 255,922	$ 388,936	$ 404,586	$ 888,391	$ 2,906,351	$ 4,412,873			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 25,976	$ 15,945	$ 22,010	$ 104,890	$ 29,018	$ 38,633	$ 236,472	$ 403,195			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 265,550	$ (91,902)	$ (160,117)	$ 213,087	$ 72,688	$ 984,365	$ 1,283,671	$ 888,028			

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 Final True-Up Amount for the Period
January 2006 - December 2006

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	$ 969,676	$ 995,590	$ (25,914)	-2.6%
3b	Continuous Emission Monitoring Systems-Capital	1,054,143	1,095,131	(40,988)	-3.7%
4b	Clean Closure Equivalency-Capital	4,134	4,304	(170)	-3.9%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	1,817,372	1,894,928	(77,556)	-4.1%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	1,640	1,718	(78)	-4.5%
8b	Oil Spill Cleanup/Response Equipment-Capital	96,475	98,707	(2,232)	-2.3%
10	Relocate Storm Water Runoff-Capital	9,926	10,423	(497)	-4.8%
NA	SO2 Allowances-Negative Return on Investment	(556,787)	(607,300)	50,513	-8.3%
12	Scherer Discharge Pipeline-Capital	65,830	68,968	(3,138)	-4.5%
17b	Disposal of Noncontainerized Liquid Wate-Capital	0	0	0	0.0%
20	Wastewater Discharge Elimination & Reuse	252,416	264,958	(12,542)	-4.7%
21	St. Lucie Turtle Net	93,750	98,692	(4,942)	-5.0%
22	Pipeline Integrity Management	0	0	0	0.0%
23	SPCC-Spill Prevention, Control & Countermeasures	1,889,405	1,985,785	(96,380)	-4.9%
24	Manatee Reburn	3,425,806	3,890,516	(464,710)	-11.9%
25	Pt. Everglades ESP Technology	6,541,388	7,073,402	(532,014)	-7.5%
26	UST Replacement/Removal	0	26,471	(26,471)	-100.0%
31	CAIR Compliance	96,817	210,309	(113,492)	-54.0%
33	CAMR Compliance	0	13,648	(13,648)	-100.0%
2	Total Investment Projects-Recoverable Costs	$ 15,761,991	$ 17,126,250	$ (1,364,259)	-8.0%
3	Recoverable Costs Allocated to Energy	$ 11,767,132	$ 12,807,256	$ (1,040,124)	-8.1%
4	Recoverable Costs Allocated to Demand	$ 3,994,859	$ 4,318,994	$ (324,135)	-7.5%

Notes:
Column(1) is the 12-Month Totals on Form 42-7A
Column(2) is the approved projected amount in accordance with FPSC Order No. PSC-06-0972-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 Final True-up Amount for the Period
January 2006 - December 2006

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	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	$83,172	$82,755	$82,316	$81,877	$81,431	$ 80,984	$ 492,535
3b	Continuous Emission Monitoring Systems-Capital	89,700	89,386	89,074	82,539	88,175	88,844	527,718
4b	Clean Closure Equivalency-Capital	350	349	348	347	346	345	2,085
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	153,688	153,281	152,873	152,466	152,059	151,651	916,018
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	138	138	138	137	137	137	825
8b	Oil Spill Cleanup/Response Equipment-Capital	10,658	10,577	10,496	10,416	10,335	10,254	62,736
10	Relocate Storm Water Runoff-Capital	834	833	832	830	829	828	4,986
NA	SO2 Allowances-Negative Return on Investment	(17,624)	(30,521)	(58,157)	(74,668)	(71,282)	(63,779)	(316,031)
12	Scherer Discharge Pipeline-Capital	5,544	5,533	5,523	5,512	5,502	5,491	33,105
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	21,672	21,779	21,408	20,975	20,941	20,907	127,682
21	St. Lucie Turtle Net	7,862	7,853	7,844	7,835	7,826	7,817	47,037
22	Pipeline Integrity Management	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	151,084	150,767	151,306	154,415	157,091	157,191	921,854
24	Manatee Rebum	263,340	264,206	266,394	269,310	270,938	272,410	1,606,598
25	Pt. Everglades ESP Technology	456,407	477,463	502,004	516,144	525,122	536,350	3,013,490
26	UST Removal / Replacement	0	0	0	0	0	0	0
31	CAIR Compliance	160	252	652	2,212	4,433	6,065	13,774
33	CAMR Compliance	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$ 1,226,985	$ 1,234,651	$ 1,233,051	$ 1,230,347	$ 1,253,883	$ 1,275,495	$ 7,454,412
3	Recoverable Costs Allocated to Energy	$ 902,071	$ 910,317	$ 908,663	$ 902,521	$ 922,038	$ 942,554	$ 5,488,164
4	Recoverable Costs Allocated to Demand	$ 324,914	$ 324,334	$ 324,388	$ 327,826	$ 331,845	$ 332,941	$ 1,966,248
5	Retail Energy Jurisdictional Factor	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	
6	Retail Demand Jurisdictional Factor	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	
7	Jurisdictional Energy Recoverable Costs (B)	$ 888,842	$ 896,967	$ 895,338	$ 889,285	$ 908,516	$ 928,731	$ 5,407,679
8	Jurisdictional Demand Recoverable Costs (C)	$ 320,437	$ 319,866	$ 319,918	$ 323,309	$ 327,273	$ 328,354	$ 1,939,157
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 1,209,279	$ 1,216,833	$ 1,215,256	$ 1,212,594	$ 1,235,789	$ 1,257,085	$ 7,346,836

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

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2006 - December 2006

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	Actual JUL	Actual AUG	Actual SEP	Actual OCT	Actual NOV	Actual 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	$ 80,569	$ 80,153	$ 79,737	$ 79,322	$ 78,906	$ 78,454	$ 477,141	$ 969,676		$ 969,676
3b	Continuous Emission Monitoring Systems-Capital	88,525	88,207	87,888	87,569	87,251	86,985	526,425	1,054,143		1,054,143
4b	Clean Closure Equivalency-Capital	344	343	342	341	340	339	2,049	4,134	3,816	318
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	151,244	150,837	150,429	150,022	149,615	149,207	901,354	1,817,372	1,677,574	139,798
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	137	136	136	136	135	135	815	1,640	1,514	126
8b	Oil Spill Cleanup/Response Equipment-Capital	7,174	4,211	4,947	5,545	5,627	6,235	33,739	96,475	89,054	7,421
10	Relocate Storm Water Runoff-Capital	827	825	824	823	821	820	4,940	9,926	9,162	764
NA	SO2 Allowances-Negative Return on Investment	(57,668)	(50,331)	(43,474)	(36,618)	(29,761)	(22,904)	(240,756)	(556,787)		(556,787)
12	Scherer Discharge Pipeline-Capital	5,481	5,470	5,459	5,449	5,438	5,428	32,725	65,830	60,766	5,064
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	20,873	20,840	20,806	20,772	20,738	20,705	124,734	252,416	232,999	19,417
21	St. Lucie Turtle Net	7,808	7,799	7,790	7,781	7,772	7,763	46,713	93,750	86,538	7,212
22	Pipeline Integrity Management	0	0	0	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	157,193	159,848	162,609	162,853	162,661	162,387	967,551	1,889,405	1,744,066	145,339
24	Manatee Reburn	274,782	277,277	279,335	292,023	314,485	381,306	1,819,208	3,425,806		3,425,806
25	Pt. Everglades ESP Technology	551,417	569,558	581,225	595,216	610,494	619,988	3,527,898	6,541,388		6,541,388
26	UST Removal / Replacement	0	0	0	0	0	0	0	0	0	0
31	CAIR Compliance	7,134	8,112	9,260	14,250	18,783	25,504	83,043	96,817	89,370	7,447
33	CAMR Compliance	0	0	0	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$ 1,295,840	$ 1,323,285	$ 1,347,313	$ 1,385,484	$ 1,433,305	$ 1,522,352	$ 8,307,579	$ 15,761,991	$ 3,994,859	$ 11,767,132
3	Recoverable Costs Allocated to Energy	$ 965,180	$ 992,435	$ 1,012,603	$ 1,045,818	$ 1,089,985	$ 1,172,946	$ 6,278,967	$ 11,767,132		
4	Recoverable Costs Allocated to Demand	$ 330,660	$ 330,850	$ 334,710	$ 339,666	$ 343,320	$ 349,406	$ 2,028,612	$ 3,994,859		
5	Retail Energy Jurisdictional Factor	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%				
6	Retail Demand Jurisdictional Factor	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%				
7	Jurisdictional Energy Recoverable Costs (B)	$ 951,025	$ 977,881	$ 997,753	$ 1,030,480	$ 1,074,000	$ 1,155,745	$ 6,186,884	$ 11,594,563		
8	Jurisdictional Demand Recoverable Costs (C)	$ 326,104	$ 326,292	$ 330,098	$ 334,987	$ 338,590	$ 344,592	$ 2,000,663	$ 3,939,820		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 1,277,129	$ 1,304,173	$ 1,327,851	$ 1,365,467	$ 1,412,590	$ 1,500,337	$ 8,187,547	$ 15,534,383		

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

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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	($8,928)	$0	$0	$0	($8,928)
	c. Retirements						$36,497		$36,497
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,611,468	17,611,468	17,611,468	17,602,540	17,602,540	17,566,043	17,566,043	n/a
3.	Less: Accumulated Depreciation (C)	13,466,542	13,511,589	13,556,637	13,592,733	13,637,735	13,646,210	13,691,151	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$4,144,926	$4,099,879	$4,054,831	$4,009,807	$3,964,805	$3,919,833	$3,874,892	n/a
6.	Average Net Investment		4,122,402	4,077,355	4,032,319	3,987,306	3,942,319	3,897,362	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		31,677	31,331	30,985	30,639	30,293	29,948	184,874
	b. Debt Component (Line 6 x 1.8767% x 1/12)		6,447	6,377	6,306	6,236	6,165	6,095	37,626
8.	Investment Expenses								
	a. Depreciation (E)		45,047	45,047	45,025	45,002	44,972	44,941	270,034
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$83,172	$82,755	$82,316	$81,877	$81,431	$80,984	$492,535

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

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	($8,928)
	c. Retirements							$56,834	$93,331
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,566,043	17,566,043	17,566,043	17,566,043	17,566,043	17,566,043	17,509,209	n/a
3.	Less: Accumulated Depreciation (C)	13,691,151	13,736,092	13,781,033	13,825,974	13,870,916	13,915,857	13,903,927	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$3,874,892	$3,829,951	$3,785,009	$3,740,068	$3,695,127	$3,650,186	$3,605,282	n/a
6.	Average Net Investment		3,852,421	3,807,480	3,762,539	3,717,598	3,672,656	3,627,734	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		29,603	29,257	28,912	28,567	28,221	27,876	357,310
	b. Debt Component (Line 6 x 1.8767% x 1/12)		6,025	5,955	5,884	5,814	5,744	5,673	72,721
8.	Investment Expenses								
	a. Depreciation (E)		44,941	44,941	44,941	44,941	44,941	44,904	539,645
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$80,569	$80,153	$79,737	$79,322	$78,906	$78,454	$969,676

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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					($9,928)	$7,403		($2,525)
	c. Retirements						$7,039		$7,039
	d. Other (A)								$0
2.	Plant-In-Service/Depreciation Base (B)	$12,615,804	12,615,804	12,615,804	12,615,804	12,605,876	12,606,240	12,606,240	0
3.	Less: Accumulated Depreciation (C)	6,553,089	6,586,876	6,620,663	6,654,449	6,682,030	6,708,503	6,742,964	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$6,062,715	$6,028,928	$5,995,142	$5,961,355	$5,923,846	$5,897,737	$5,863,276	n/a
6.	Average Net Investment		6,045,821	6,012,035	5,978,248	5,942,601	5,910,792	5,880,507	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		46,457	46,197	45,938	45,664	45,420	45,187	274,863
	b. Debt Component (Line 6 x 1.8767% x 1/12)		9,455	9,402	9,349	9,294	9,244	9,197	55,941
8.	Investment Expenses								
	a. Depreciation (E)		33,787	33,786	33,786	27,581	33,512	34,461	196,914
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$89,700	$89,386	$89,074	$82,539	$88,175	$88,844	$527,718

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

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							$7,606	$5,081
	c. Retirements								$7,039
	d. Other (A)								$0
2.	Plant-In-Service/Depreciation Base (B)	$12,606,240	12,606,240	12,606,240	12,606,240	12,606,240	12,606,240	12,613,846	n/a
3.	Less: Accumulated Depreciation (C)	6,742,964	6,777,424	6,811,885	6,846,346	6,880,806	6,915,267	6,949,745	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$5,863,276	$5,828,816	$5,794,355	$5,759,895	$5,725,434	$5,690,973	$5,664,101	n/a
6.	Average Net Investment		5,846,046	5,811,586	5,777,125	5,742,664	5,708,204	5,677,537	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		44,922	44,657	44,392	44,128	43,863	43,627	540,452
	b. Debt Component (Line 6 x 1.8767% x 1/12)		9,143	9,089	9,035	8,981	8,927	8,879	109,995
8.	Investment Expenses								
	a. Depreciation (E)		34,461	34,461	34,461	34,461	34,461	34,478	403,695
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$88,525	$88,207	$87,888	$87,569	$87,251	$86,985	$1,054,143

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(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 2006

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)	32,922	33,033	33,143	33,254	33,365	33,476	33,587	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$25,944	$25,833	$25,723	$25,612	$25,501	$25,390	$25,279	n/a
6.	Average Net Investment		25,889	25,778	25,667	25,556	25,445	25,335	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		199	198	197	196	196	195	1,181
	b. Debt Component (Line 6 x 1.8767% x 1/12)		40	40	40	40	40	40	240
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$350	$349	$348	$347	$346	$345	$2,085

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

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)	33,587	33,698	33,808	33,919	34,030	34,141	34,252	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$25,279	$25,168	$25,058	$24,947	$24,836	$24,725	$24,614	n/a
6.	Average Net Investment		25,224	25,113	25,002	24,891	24,781	24,670	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		194	193	192	191	190	190	2,331
	b. Debt Component (Line 6 x 1.8767% x 1/12)		39	39	39	39	39	39	474
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	1,330
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$344	$343	$342	$341	$340	$339	$4,134

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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)	$13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	n/a
3.	Less: Accumulated Depreciation (C)	1,672,594	1,716,640	1,760,687	1,804,733	1,848,780	1,892,826	1,936,872	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,877,624	$11,833,578	$11,789,531	$11,745,485	$11,701,438	$11,657,392	$11,613,346	n/a
6.	Average Net Investment		11,855,601	11,811,554	11,767,508	11,723,461	11,679,415	11,635,369	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		91,100	90,762	90,424	90,085	89,747	89,408	541,526
	b. Debt Component (Line 6 x 1.8767% x 1/12)		18,541	18,472	18,403	18,335	18,266	18,197	110,214
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,046	44,046	44,046	44,046	44,046	264,278
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$153,688	$153,281	$152,873	$152,466	$152,058	$151,651	$916,017

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

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
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	n/a
3.	Less: Accumulated Depreciation (C)	1,936,872	1,980,919	2,024,965	2,069,012	2,113,058	2,157,104	2,201,151	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,613,346	$11,569,299	$11,525,253	$11,481,206	$11,437,160	$11,393,113	$11,349,067	n/a
6.	Average Net Investment		11,591,322	11,547,276	11,503,229	11,459,183	11,415,137	11,371,090	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		89,070	88,731	88,393	88,054	87,716	87,377	1,070,867
	b. Debt Component (Line 6 x 1.8767% x 1/12)		18,128	18,059	17,990	17,921	17,852	17,783	217,948
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,046	44,046	44,046	44,046	44,046	528,557
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$151,244	$150,837	$150,429	$150,022	$149,615	$149,207	$1,817,371

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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)	19,410	19,441	19,472	19,503	19,534	19,565	19,596	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,620	$11,589	$11,558	$11,527	$11,496	$11,465	$11,434	n/a
6.	Average Net Investment		11,605	11,574	11,543	11,512	11,481	11,450	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		89	89	89	88	88	88	531
	b. Debt Component (Line 6 x 1.8767% x 1/12)		18	18	18	18	18	18	108
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	186
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$138	$138	$138	$137	$137	$137	$825

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

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)	19,596	19,627	19,658	19,689	19,720	19,751	19,782	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,434	$11,403	$11,372	$11,341	$11,310	$11,279	$11,248	n/a
6.	Average Net Investment		11,419	11,388	11,357	11,326	11,294	11,263	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		88	88	87	87	87	87	1,054
	b. Debt Component (Line 6 x 1.8767% x 1/12)		18	18	18	18	18	18	215
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	372
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$137	$136	$136	$136	$135	$135	$1,640

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 42-8A, pages 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$756,680	756,680	756,680	756,680	756,680	756,680	756,680	n/a
3.	Less: Accumulated Depreciation (C)	544,410	553,145	561,880	570,615	579,350	588,085	596,821	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$212,270	$203,535	$194,800	$186,065	$177,330	$168,595	$159,860	n/a
6.	Average Net Investment		207,903	199,168	190,432	181,697	172,962	164,227	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,598	1,530	1,463	1,396	1,329	1,262	8,579
	b. Debt Component (Line 6 x 1.8767% x 1/12)		325	311	298	284	270	257	1,746
8.	Investment Expenses								
	a. Depreciation (E)		8,735	8,735	8,735	8,735	8,735	8,735	52,411
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$10,658	$10,577	$10,496	$10,416	$10,335	$10,254	$62,736

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 42-8A, pages 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

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		$3,728	$8,505	$19,607	$45,228	$4,225	$18,459	$99,752
	c. Retirements			$513,930					
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$756,680	760,408	254,983	274,590	319,818	324,044	342,502	n/a
3.	Less: Accumulated Depreciation (C)	596,821	602,525	91,320	94,678	98,368	101,943	106,058	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$159,860	$157,883	$163,663	$179,912	$221,451	$222,100	$236,445	n/a
6.	Average Net Investment		158,871	160,773	171,788	200,681	221,776	229,273	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,221	1,235	1,320	1,542	1,704	1,762	17,363
	b. Debt Component (Line 6 x 1.8767% x 1/12)		248	251	269	314	347	359	3,534
8.	Investment Expenses								
	a. Depreciation (E)		5,704	2,724	3,358	3,690	3,576	4,114	75,577
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,174	$4,211	$4,947	$5,545	$5,627	$6,235	$96,475

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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)	42,388	42,526	42,663	42,801	42,938	43,075	43,212	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$75,406	$75,268	$75,131	$74,993	$74,856	$74,719	$74,582	n/a
6.	Average Net Investment		75,337	75,200	75,062	74,925	74,788	74,650	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		579	578	577	576	575	574	3,458
	b. Debt Component (Line 6 x 1.8767% x 1/12)		118	118	117	117	117	117	704
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	824
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$834	$833	$832	$830	$829	$828	$4,986

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

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)	43,212	43,350	43,487	43,625	43,762	43,899	44,037	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$74,582	$74,444	$74,307	$74,169	$74,032	$73,895	$73,757	n/a
6.	Average Net Investment		74,513	74,375	74,238	74,101	73,963	73,826	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		573	572	570	569	568	567	6,877
	b. Debt Component (Line 6 x 1.8767% x 1/12)		117	116	116	116	116	115	1,400
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	1,648
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$827	$825	$824	$823	$821	$820	$9,926

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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)	387,378	388,516	389,655	390,794	391,933	393,071	394,210	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$476,882	$475,744	$474,605	$473,466	$472,327	$471,189	$470,050	n/a
6.	Average Net Investment		476,313	475,174	474,035	472,897	471,758	470,619	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,660	3,651	3,643	3,634	3,625	3,616	21,829
	b. Debt Component (Line 6 x 1.8767% x 1/12)		745	743	741	740	738	736	4,443
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	6,833
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,544	$5,533	$5,523	$5,512	$5,502	$5,491	$33,105

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

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)	394,210	395,349	396,488	397,626	398,765	399,904	401,043	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$470,050	$468,911	$467,772	$466,634	$465,495	$464,356	$463,217	n/a
6.	Average Net Investment		469,480	468,342	467,203	466,064	464,925	463,787	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,608	3,599	3,590	3,581	3,573	3,564	43,343
	b. Debt Component (Line 6 x 1.8767% x 1/12)		734	732	731	729	727	725	8,821
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	13,665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,481	$5,470	$5,459	$5,449	$5,438	$5,428	$65,830

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

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)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% 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 42-8A, pages 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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		$14,982	$11,971	($75,100)	$0	$0	$0	($48,147)
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,409,809	2,424,791	2,436,762	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	475,197	478,926	482,671	486,372	490,021	493,670	497,318	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,934,612	$1,945,865	$1,954,091	$1,875,289	$1,871,641	$1,867,992	$1,864,343	n/a
6.	Average Net Investment		1,940,238	1,949,978	1,914,690	1,873,465	1,869,816	1,866,168	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		14,909	14,984	14,713	14,396	14,368	14,340	87,710
	b. Debt Component (Line 6 x 1.8767% x 1/12)		3,034	3,050	2,994	2,930	2,924	2,919	17,851
8.	Investment Expenses								
	a. Depreciation (E)		3,729	3,746	3,701	3,649	3,649	3,649	22,121
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$21,672	$21,779	$21,408	$20,975	$20,941	$20,907	$127,682

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

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	($48,147)
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	$497,318	500,967	504,616	508,265	511,913	515,562	519,211	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,864,343	$1,860,695	$1,857,046	$1,853,397	$1,849,748	$1,846,100	$1,842,451	n/a
6.	Average Net Investment		1,862,519	1,858,870	1,855,221	1,851,573	1,847,924	1,844,275	
7.	Return on Average Net Investment								
	Equity Component grossed up for taxes (D)		14,312	14,284	14,256	14,228	14,200	14,172	173,161
	Debt Component (Line 6 x 1.8767% x 1/12)		2,913	2,907	2,901	2,896	2,890	2,884	35,242
8.	Investment Expenses								
	a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	44,013
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$20,873	$20,840	$20,806	$20,772	$20,738	$20,705	$252,416

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$828,789	828,789	828,789	828,789	828,789	828,789	828,789	n/a
3.	Less: Accumulated Depreciation (C)	82,785	83,752	84,719	85,686	86,653	87,620	88,587	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$746,004	$745,037	$744,070	$743,103	$742,136	$741,169	$740,202	n/a
6.	Average Net Investment		745,520	744,553	743,587	742,620	741,653	740,686	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		5,729	5,721	5,714	5,706	5,699	5,692	34,261
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,166	1,164	1,163	1,161	1,160	1,158	6,973
8.	Investment Expenses								
	a. Depreciation (E)		967	967	967	967	967	967	5,802
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,862	$7,853	$7,844	$7,835	$7,826	$7,817	$47,037

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G)

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$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)	$88,587	89,554	90,521	91,487	92,454	93,421	94,388	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$740,202	$739,235	$738,268	$737,302	$736,335	$735,368	$734,401	n/a
6.	Average Net Investment		739,719	738,752	737,785	736,818	735,851	734,884	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		5,684	5,677	5,669	5,662	5,654	5,647	68,254
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,157	1,155	1,154	1,152	1,151	1,149	13,891
8.	Investment Expenses								
	a. Depreciation (E)		967	967	967	967	967	967	11,603
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,808	$7,799	$7,790	$7,781	$7,772	$7,763	$93,750

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(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 2006

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 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(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)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$1,911	$1,189	$158,385	$485,262	$82,300	$1,033	$730,079
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,043,109	13,045,019	13,046,208	13,204,593	13,689,854	13,772,154	13,773,188	n/a
3.	Less: Accumulated Depreciation (C)	601,242	637,421	673,603	709,922	746,712	783,896	821,138	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$12,441,867	$12,407,599	$12,372,605	$12,494,670	$12,943,142	$12,988,259	$12,952,050	n/a
6.	Average Net Investment		12,424,733	12,390,102	12,433,638	12,718,906	12,965,701	12,970,154	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		95,474	95,208	95,542	97,734	99,631	99,665	583,253
	b. Debt Component (Line 6 x 1.8767% x 1/12)		19,431	19,377	19,445	19,891	20,277	20,284	118,706
8.	Investment Expenses								
	a. Depreciation (E)		36,179	36,182	36,319	36,790	37,183	37,242	219,896
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$151,084	$150,767	$151,306	$154,415	$157,091	$157,191	$921,854

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$61,683	$415,204	$68,565	$27,164	$256	$18,388	$1,321,339
	c. Retirements								
	d. Other (A)		$27						
2.	Plant-In-Service/Depreciation Base (B)	$13,773,188	13,834,871	14,250,075	14,318,640	14,345,803	14,346,060	14,364,448	n/a
3.	Less: Accumulated Depreciation (C)	$821,138	858,463	896,561	935,539	974,679	1,013,862	1,053,048	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$12,952,050	$12,976,408	$13,353,514	$13,383,101	$13,371,125	$13,332,198	$13,311,400	n/a
6.	Average Net Investment		12,964,229	13,164,961	13,368,307	13,377,113	13,351,661	13,321,799	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		99,619	101,162	102,724	102,792	102,596	102,367	1,194,514
	b. Debt Component (Line 6 x 1.8767% x 1/12)		20,275	20,589	20,907	20,921	20,881	20,834	243,113
8.	Investment Expenses								
	a. Depreciation (E)		37,299	38,097	38,978	39,140	39,183	39,186	451,779
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$157,193	$159,848	$162,609	$162,853	$162,661	$162,387	$1,889,405

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$10,016	$200,564	$88,691	$544,593	($137,292)	$510,278	$1,216,850
	b. Clearings to Plant		($86,178)	$153,250	$58,962	$23,315	$22,596	$23,729	$195,674
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$14,956,035	14,869,858	15,023,108	15,082,070	15,105,385	15,127,980	15,151,709	n/a
3.	Less: Accumulated Depreciation (C)	6,534	66,186	125,972	186,182	246,557	307,024	367,583	n/a
4.	CWIP - Non Interest Bearing	7,143,289	7,153,305	7,353,869	7,442,560	7,987,153	7,849,861	8,360,139	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$22,092,790	$21,956,977	$22,251,005	$22,338,448	$22,845,981	$22,670,818	$23,144,265	n/a
6.	Average Net Investment		22,024,883	22,103,991	22,294,726	22,592,214	22,758,399	22,907,541	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		169,243	169,851	171,316	173,602	174,879	176,025	1,034,917
	b. Debt Component (Line 6 x 1.8767% x 1/12)		34,445	34,569	34,867	35,332	35,592	35,825	210,631
8.	Investment Expenses								
	a. Depreciation (E)		59,652	59,786	60,210	60,375	60,467	60,559	361,049
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$263,340	$264,206	$266,394	$269,310	$270,938	$272,410	$1,606,598

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(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		$67,540	$136,218	($9,429)	$2,864,754	$2,110,017	$0	$6,385,950
	b. Clearings to Plant		$15,500	$304,154	$3,933	$4,678	($1)	$14,743,193	$15,267,131
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$15,151,709	15,167,209	15,471,364	15,475,297	15,479,975	15,479,974	30,223,167	n/a
3.	Less: Accumulated Depreciation (C)	$367,583	428,221	489,498	551,391	613,302	675,222	789,407	n/a
4.	CWIP - Non Interest Bearing	$8,360,139	8,427,679	8,563,897	8,554,468	11,419,222	13,529,239	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$23,144,265	$23,166,667	$23,545,762	$23,478,374	$26,285,895	$28,333,991	$29,433,759	n/a
6.	Average Net Investment		23,155,466	23,356,215	23,512,068	24,882,135	27,309,943	28,883,875	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		177,930	179,473	180,671	191,198	209,854	221,949	$2,195,993
	b. Debt Component (Line 6 x 1.8767% x 1/12)		36,213	36,527	36,771	38,914	42,710	45,172	$446,938
8.	Investment Expenses								
	a. Depreciation (E)		60,638	61,277	61,893	61,911	61,920	114,186	$782,874
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$274,782	$277,277	$279,335	$292,023	$314,485	$381,306	$3,425,806

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$1,177,920	$2,316,450	$2,147,506	$893,818	$1,227,001	$1,412,558	$9,175,253
	b. Clearings to Plant		$298,913	$563,854	$164,630	$41,388	$41,295	$20,829	$1,130,909
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$28,690,716	28,989,629	29,553,482	29,718,113	29,759,501	29,800,796	29,821,625	n/a
3.	Less: Accumulated Depreciation (C)	732,731	882,069	1,033,706	1,187,286	1,341,412	1,495,754	1,650,259	n/a
4.	CWIP - Non Interest Bearing	4,581,878	5,759,798	8,076,248	10,223,753	11,117,571	12,344,572	13,757,130	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$32,539,862	$33,867,358	$36,596,024	$38,754,580	$39,535,660	$40,649,614	$41,928,496	n/a
6.	Average Net Investment		33,203,610	35,231,691	37,675,302	39,145,120	40,092,637	41,289,055	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		255,142	270,726	289,503	300,798	308,079	317,272	1,741,520
	b. Debt Component (Line 6 x 1.8767% x 1/12)		51,928	55,099	58,921	61,220	62,702	64,573	354,442
8.	Investment Expenses								
	a. Depreciation (E)		149,337	151,637	153,580	154,127	154,342	154,505	917,528
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$456,407	$477,463	$502,004	$516,144	$525,122	$536,350	$3,013,490

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(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		$2,084,011	$2,058,536	$683,621	$2,583,286	$995,428	$1,350,380	$18,930,516
	b. Clearings to Plant		$24,478	$33,141	$24,567	$19,172	$3,582	$7,592	$1,243,440
	c. Retirements		$0	$0	$0	$0	$0		$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$29,821,625	29,846,103	29,879,244	29,903,810	29,922,982	29,926,564	29,934,156	n/a
3.	Less: Accumulated Depreciation (C)	$1,650,259	1,804,884	1,959,658	2,114,584	2,269,626	2,424,727	2,579,857	n/a
4.	CWIP - Non Interest Bearing	$13,757,130	15,841,142	17,899,678	18,583,299	21,166,585	22,162,013	23,512,393	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$41,928,496	$43,882,361	$45,819,264	$46,372,525	$48,819,942	$49,663,850	$50,866,692	n/a
6.	Average Net Investment		42,905,429	44,850,812	46,095,894	47,596,233	49,241,896	50,265,271	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		329,693	344,641	354,209	365,737	378,383	386,247	$3,900,429
	b. Debt Component (Line 6 x 1.8767% x 1/12)		67,101	70,143	72,090	74,437	77,010	78,611	$793,833
8.	Investment Expenses								
	a. Depreciation (E)		154,624	154,774	154,926	155,042	155,101	155,130	$1,847,126
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$551,417	$569,558	$581,225	$595,216	$610,494	$619,988	$6,541,388

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 42-8A, pages 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% 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 42-8A, pages 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		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 42-8A, pages 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(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		$9,583	$10,337	$76,152	$261,118	$219,266	$133,626	$710,082
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	12,507	22,091	32,427	108,579	369,697	588,963	722,589	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$12,507	$22,091	$32,427	$108,579	$369,697	$588,963	$722,589	n/a
6.	Average Net Investment		17,299	27,259	70,503	239,138	479,330	655,776	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		133	209	542	1,838	3,683	5,039	11,444
	b. Debt Component (Line 6 x 1.8767% x 1/12)		27	43	110	374	750	1,026	2,329
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)		$160	$252	$652	$2,212	$4,433	$6,065	$13,774

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(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		$97,666	$113,836	$134,353	$944,799	$35,550	$1,417,882	$3,454,169
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$722,589	820,255	934,092	1,068,445	2,013,244	2,048,794	3,466,676	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$722,589	$820,255	$934,092	$1,068,445	$2,013,244	$2,048,794	$3,466,676	n/a
6.	Average Net Investment		771,422	877,174	1,001,268	1,540,844	2,031,019	2,757,735	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		5,928	6,740	7,694	11,840	15,607	21,191	$80,444
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,206	1,372	1,566	2,410	3,176	4,313	$16,372
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)		$7,134	$8,112	$9,260	$14,250	$18,783	$25,504	$96,817

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 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	n/a
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	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% 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 42-8A, pages 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% 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 42-8A, pages 39-41.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 39-41.
(F) Applicable amortization period(s). See Form 42-8A, pages 39-41.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

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	(1,921,037)	(1,890,395)	(4,710,134)	(7,866,898)	(8,280,895)	(7,134,617)	(6,658,321)		
2	Total Working Capital	($1,921,037)	($1,890,395)	($4,710,134)	($7,866,898)	($8,280,895)	($7,134,617)	($6,658,321)		
3	Average Net Working Capital Balance		(1,905,716)	(3,300,264)	(6,288,516)	(8,073,896)	(7,707,756)	(6,896,469)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(14,644)	(25,360)	(48,322)	(62,041)	(59,228)	(52,994)	(262,588)	
	b Debt Component (Line 6 x 1.6698% x 1/12)		(2,980)	(5,161)	(9,835)	(12,627)	(12,054)	(10,786)	(53,443)	
5	Total Return Component		($17,624)	($30,521)	($58,157)	($74,668)	($71,282)	($63,779)	($316,031)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(30,642)	(30,642)	(743,237)	(1,568,173)	(1,223,370)	(748,623)	(4,344,687)	
	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)		($30,642)	($30,642)	($743,237)	($1,568,173)	($1,223,370)	($748,623)	($4,344,687)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(48,266)	(61,163)	(801,393)	(1,642,841)	(1,294,652)	(812,402)		
	a Recoverable Costs Allocated to Energy		(48,266)	(61,163)	(801,393)	(1,642,841)	(1,294,652)	(812,402)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%		
10	Demand Jurisdictional Factor		98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%		
11	Retail Energy-Related Recoverable Costs (B)		(47,558)	(60,266)	(789,641)	(1,618,749)	(1,275,666)	(800,488)	(4,592,368)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($47,558)	($60,266)	($789,641)	($1,618,749)	($1,275,666)	($800,488)	($4,592,368)	

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 5.6640% reflects an 11.75% 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 2006

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	(6,658,321)	(5,813,038)	(5,071,614)	(4,330,190)	(3,588,765)	(2,847,341)	(2,105,917)		
2	Total Working Capital	($6,658,321)	($5,813,038)	($5,071,614)	($4,330,190)	($3,588,765)	($2,847,341)	($2,105,917)		
3	Average Net Working Capital Balance		(6,235,680)	(5,442,326)	(4,700,902)	(3,959,478)	(3,218,053)	(2,476,629)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(47,916)	(41,820)	(36,123)	(30,425)	(24,728)	(19,031)	(462,631)	
	b Debt Component (Line 6 x 1.6698% x 1/12)		(9,752)	(8,511)	(7,352)	(6,192)	(5,033)	(3,873)	(94,157)	
5	Total Return Component		($57,668)	($50,331)	($43,474)	($36,618)	($29,761)	($22,904)	($556,787)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(845,283)	(741,424)	(741,424)	(741,424)	(741,424)	(741,424)	(8,897,092)	
	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)		($845,283)	($741,424)	($741,424)	($741,424)	($741,424)	($741,424)	($8,897,092)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		($902,951)	($791,755)	($784,899)	($778,042)	($771,185)	($764,328)		
	a Recoverable Costs Allocated to Energy		(902,951)	(791,755)	(784,899)	(778,042)	(771,185)	(764,328)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%		
10	Demand Jurisdictional Factor		98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%		
11	Retail Energy-Related Recoverable Costs (B)		(889,709)	(780,144)	(773,388)	(766,632)	(759,876)	(753,119)	(9,315,236)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($889,709)	($780,144)	($773,388)	($766,632)	($759,876)	($753,119)	($9,315,236)	

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 5.6640% reflects an 11.75% 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
2006 Annual Capital Depreciation Schedule

Project Number	Function	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Actual 12/31/2005 Plant In Service	Actual 12/31/2006 Plant In Service
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.7%	$2,700,574.97	$2,700,574.97
	02 - Steam Generation Plant	PtEverglades U2	31200	6.1%	$2,377,900.75	$2,368,972.27
	02 - Steam Generation Plant	Riviera U3	31200	1.7%	$3,846,591.65	$3,815,802.70
	02 - Steam Generation Plant	Riviera U4	31200	1.4%	$3,272,970.68	$3,246,925.80
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.0%	$2,961,524.84	$2,925,027.84
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.8%	$2,451,904.92	$2,451,904.92
		Total For Project 02 - Low NOX Burner Technology			**$17,611,467.81**	**$17,509,208.50**
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	$59,227.10	$59,227.10
	02 - Steam Generation Plant	Cutler Comm	31100	0.0%	$64,883.87	$64,883.87
	02 - Steam Generation Plant	Manatee U1	31100	4.1%	$56,430.25	$56,430.25
	02 - Steam Generation Plant	Manatee U2	31100	4.1%	$56,332.75	$56,332.75
	02 - Steam Generation Plant	Martin U1	31100	1.5%	$36,810.86	$36,810.86
	02 - Steam Generation Plant	Martin U2	31100	1.5%	$36,845.37	$36,845.37
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	$127,911.34	$127,911.34
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	$60,973.18	$60,973.18
	02 - Steam Generation Plant	Sanford U3	31100	4.0%	$54,282.08	$54,282.08
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.1%	$43,193.33	$43,193.33
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.3%	$59,056.19	$59,056.19
	02 - Steam Generation Plant	CapeCanaveral Comm	31200	1.3%	$30,059.25	$30,059.25
	02 - Steam Generation Plant	CapeCanaveral U1	31200	1.4%	$494,606.87	$494,606.87
	02 - Steam Generation Plant	CapeCanaveral U2	31200	1.1%	$511,705.24	$511,705.24
	02 - Steam Generation Plant	Cutler Comm	31200	0.5%	$27,351.73	$27,351.73
	02 - Steam Generation Plant	Cutler U5	31200	0.0%	$312,722.43	$312,722.43
	02 - Steam Generation Plant	Cutler U6	31200	1.0%	$314,129.96	$314,129.96
	02 - Steam Generation Plant	Manatee Comm	31200	14.1%	$31,859.00	$31,859.00
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	$472,570.03	$472,570.03
	02 - Steam Generation Plant	Manatee U2	31200	4.0%	$508,734.36	$508,734.36
	02 - Steam Generation Plant	Martin Comm	31200	4.1%	$31,631.74	$31,631.74
	02 - Steam Generation Plant	Martin U1	31200	1.8%	$521,075.17	$521,075.17
	02 - Steam Generation Plant	Martin U2	31200	1.5%	$519,484.96	$519,484.96
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.2%	$61,620.47	$61,620.47
	02 - Steam Generation Plant	PtEverglades U1	31200	6.7%	$453,661.22	$453,661.22
	02 - Steam Generation Plant	PtEverglades U2	31200	6.1%	$475,113.36	$475,113.36
	02 - Steam Generation Plant	PtEverglades U3	31200	4.0%	$503,968.62	$503,968.62
	02 - Steam Generation Plant	PtEverglades U4	31200	3.6%	$512,809.90	$512,809.90
	02 - Steam Generation Plant	Riviera Comm	31200	0.4%	$29,117.75	$29,117.75
	02 - Steam Generation Plant	Riviera U3	31200	1.7%	$449,392.38	$449,392.38
	02 - Steam Generation Plant	Riviera U4	31200	1.4%	$433,421.96	$433,421.96
	02 - Steam Generation Plant	Sanford U3	31200	3.6%	$116,944.80	$431,831.34
	02 - Steam Generation Plant	Sanford U3 (Retiring)	31200	0.0%	$315,699.69	$0.00
	02 - Steam Generation Plant	Scherer U4	31200	1.9%	$515,653.32	$515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.0%	$66,188.18	$66,188.18
	02 - Steam Generation Plant	SJRPP U1	31200	2.2%	$107,594.02	$107,594.02
	02 - Steam Generation Plant	SJRPP U2	31200	2.3%	$107,562.94	$107,562.94
	02 - Steam Generation Plant	Turkey Pt Comm	31200	2.1%	$29,110.85	$29,110.85
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.0%	$546,534.15	$546,534.15
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.8%	$505,638.44	$505,638.44
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.1%	$58,859.79	$58,859.79
	05 - Other Generation Plant	Putnam Comm	34100	4.1%	$82,857.82	$82,857.82
	05 - Other Generation Plant	FtLauderdale U4	34300	5.0%	$461,080.14	$461,080.14
	05 - Other Generation Plant	FtLauderdale U5	34300	3.7%	$471,313.47	$471,313.47
	05 - Other Generation Plant	FtMyers U2	34300	5.5%	$101,353.39	$106,324.08
	05 - Other Generation Plant	FtMyers U3	34300	5.6%	$0.00	$2,635.22
	05 - Other Generation Plant	Martin U3	34300	5.8%	$431,927.00	$431,927.00
	05 - Other Generation Plant	Martin U4	34300	5.7%	$421,026.31	$421,026.31
	05 - Other Generation Plant	Martin U8	34300	5.5%	$25,657.00	$25,657.00
	05 - Other Generation Plant	Putnam Comm	34300	6.3%	$3,138.97	$3,138.97
	05 - Other Generation Plant	Putnam U1	34300	5.2%	$335,440.55	$335,440.55
	05 - Other Generation Plant	Putnam U2	34300	5.4%	$368,844.07	$368,844.07
	05 - Other Generation Plant	Sanford Comm	34300	5.9%	$5,168.21	$0.00
	05 - Other Generation Plant	Sanford U4	34300	5.6%	$41,859.48	$45,032.12
	05 - Other Generation Plant	Sanford U5	34300	5.7%	$100,938.52	$104,111.16
	05 - Other Generation Plant	FtLauderdale Comm	34500	4.1%	$34,502.21	$34,502.21
	08 - General Plant	General Plant	39190	3 YR	$9,927.75	$0.00
		Total For Project 03 - Continuous Emission Monitoring			**$12,615,803.79**	**$12,613,845.87**

Florida Power & Light Company
Environmental Cost Recovery Clause
2006 Annual Capital Depreciation Schedule

Project Number	Function	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Actual 12/31/2005 Plant In Service	Actual 12/31/2006 Plant In Service
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	$17,254.20	$17,254.20
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	$19,812.30	$19,812.30
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.3%	$21,799.28	$21,799.28
		Total For Project 04 - Clean Closure Equivalency Demonstration			**$58,865.78**	**$58,865.78**
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	$901,636.88	$901,636.88
	02 - Steam Generation Plant	Manatee Comm	31100	4.9%	$3,111,263.35	$3,111,263.35
	02 - Steam Generation Plant	Martin Comm	31100	1.7%	$1,110,450.32	$1,110,450.32
	02 - Steam Generation Plant	Martin U1	31100	1.5%	$176,338.83	$176,338.83
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	$1,132,078.22	$1,132,078.22
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	$1,081,354.77	$1,081,354.77
	02 - Steam Generation Plant	Sanford U3	31100	4.0%	$796,754.11	$796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.1%	$42,091.24	$42,091.24
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.3%	$87,560.23	$87,560.23
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.1%	$42,158.96	$42,158.96
	02 - Steam Generation Plant	Manatee Comm	31200	14.1%	$174,543.23	$174,543.23
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	$104,845.35	$104,845.35
	02 - Steam Generation Plant	Manatee U2	31200	4.0%	$127,429.19	$127,429.19
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.0%	$2,292.39	$2,292.39
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.4%	$898,110.65	$898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.5%	$584,290.23	$584,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	5.0%	$68,893.65	$68,893.65
	05 - Other Generation Plant	PtEverglades GTs	34200	5.1%	$2,359,099.94	$2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	3.7%	$749,025.94	$749,025.94
		Total For Project 05 - Maintenance of Above Ground Fuel Tanks			**$13,550,217.48**	**$13,550,217.48**
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	StLucie U1	32300	1.2%	$31,030.00	$31,030.00
		Total For Project 07 - Relocate Turbine Lube Oil Piping			**$31,030.00**	**$31,030.00**
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Martin Comm	31600	3.2%	$23,107.32	$23,107.32
	02 - Steam Generation Plant	Martin Comm	31650	5 YR	$15,228.31	$0.00
	02 - Steam Generation Plant	CapeCanaveral Comm	31670	7 YR	$17,734.13	$26,239.13
	02 - Steam Generation Plant	Manatee Comm	31670	7 YR	$4,228.28	$11,861.15
	02 - Steam Generation Plant	Martin Comm	31670	7 YR	$581,139.34	$109,127.14
	02 - Steam Generation Plant	PtEverglades Comm	31670	7 YR	$14,848.95	$47,767.08
	02 - Steam Generation Plant	Riviera Comm	31670	7 YR	$0.00	$12,491.00
	02 - Steam Generation Plant	Sanford Comm	31670	7 YR	$23,177.32	$0.00
	02 - Steam Generation Plant	Sanford U3	31670	7 YR	$6,776.50	$29,953.82
	02 - Steam Generation Plant	Turkey Pt Comm	31670	7 YR	$29,315.41	$35,096.72
	02 - Steam Generation Plant	Turkey Pt U1	31670	7 YR	$1,159.18	$1,159.18
	05 - Other Generation Plant	FtLauderdale Comm	34670	7 YR	$3,280.00	$3,280.00
	05 - Other Generation Plant	FtMyers Comm	34670	7 YR	$25,943.15	$31,677.58
	05 - Other Generation Plant	Putnam Comm	34670	7 YR	$10,741.96	$10,741.96
		Total For Project 08 - Oil Spill Clean-up/Response Equipment			**$756,679.85**	**$342,502.08**
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.4%	$117,793.83	$117,793.83
		Total For Project 10 - Reroute Storm Water Runoff			**$117,793.83**	**$117,793.83**
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31000	0.0%	$9,936.72	$9,936.72
	02 - Steam Generation Plant	Scherer Comm	31100	1.6%	$524,872.97	$524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	1.6%	$328,761.62	$328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	1.0%	$689.11	$689.11
		Total For Project 12 - Scherer Discharge Pipline			**$864,260.42**	**$864,260.42**
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	$706,500.94	$706,500.94
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	$296,707.34	$296,707.34
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	$560,786.81	$560,786.81
	02 - Steam Generation Plant	Martin U1	31200	1.8%	$422,020.89	$380,994.77
	02 - Steam Generation Plant	Martin U2	31200	1.5%	$423,792.95	$416,671.92
		Total For Project 20 - Wastewater/Stormwater Discharge Elimination			**$2,409,808.93**	**$2,361,661.78**
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.4%	$828,789.34	$828,789.34
		Total For Project 21 - St. Lucie Turtle Nets			**$828,789.34**	**$828,789.34**

Florida Power & Light Company
Environmental Cost Recovery Clause
2006 Annual Capital Depreciation Schedule

Project Number	Function	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Actual 12/31/2005 Plant In Service	Actual 12/31/2006 Plant In Service
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	$13,451.85	$665,907.33
	02 - Steam Generation Plant	Manatee Comm	31100	4.9%	$95,458.00	$95,458.00
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	$10,379.00	$10,379.00
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	$205,014.03	$205,014.03
	02 - Steam Generation Plant	Sanford U3	31100	4.0%	$418,952.78	$213,687.21
	02 - Steam Generation Plant	Riviera U3	31200	1.7%	$736,958.97	$736,958.97
	02 - Steam Generation Plant	Riviera U4	31200	1.4%	$894,298.77	$894,298.77
	02 - Steam Generation Plant	Sanford U3	31200	3.6%	$6,461.65	$211,727.22
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.7%	$13,451.85	$13,451.85
	02 - Steam Generation Plant	Cutler Comm	31400	0.0%	$12,236.00	$12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	0.2%	$0.00	$18,388.00
	02 - Steam Generation Plant	CapeCanaveral Comm	31500	1.9%	$13,450.30	$13,450.30
	02 - Steam Generation Plant	Manatee Comm	31500	3.7%	$5,000.00	$5,000.00
	02 - Steam Generation Plant	Turkey Pt Comm	31500	2.1%	$13,559.00	$13,559.00
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.1%	$189,219.17	$189,219.17
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.2%	$92,726.74	$92,726.74
	05 - Other Generation Plant	FtMyers GTs	34100	2.1%	$98,714.92	$98,714.92
	05 - Other Generation Plant	Martin Comm	34100	3.4%	$61,215.95	$61,215.95
	05 - Other Generation Plant	PtEverglades GTs	34100	1.5%	$454,080.68	$454,080.68
	05 - Other Generation Plant	Putnam Comm	34100	4.1%	$122,476.79	$148,511.20
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.4%	$1,059,696.88	$1,480,169.46
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.5%	$513,250.07	$513,250.07
	05 - Other Generation Plant	FtMyers GTs	34200	5.0%	$629,983.29	$629,983.29
	05 - Other Generation Plant	PtEverglades GTs	34200	5.1%	$1,703,610.61	$1,703,610.61
	05 - Other Generation Plant	Putnam Comm	34200	3.7%	$1,713,191.94	$1,713,191.94
	05 - Other Generation Plant	FtLauderdale Comm	34300	1.8%	$28,250.00	$28,250.00
	05 - Other Generation Plant	FtMyers U2	34300	5.5%	$49,727.00	$49,727.00
	05 - Other Generation Plant	FtMyers GTs	34500	2.9%	$12,430.00	$12,430.00
	05 - Other Generation Plant	FtMyers U3	34500	4.8%	$12,430.00	$12,430.00
	05 - Other Generation Plant	Putnam Comm	34500	4.2%	$0.00	$60,746.93
	05 - Other Generation Plant	Sanford Comm	34670	7 YR	$7,065.10	$7,065.10
	06 - Transmission Plant - Electric	Transmission Plant - Electric	35200	2.5%	$926,587.81	$951,562.91
	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.8%	$177,981.88	$177,981.88
	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	2.6%	$2,751,797.17	$2,862,088.65
	08 - General Plant	General Plant	39000	2.7%	$0.00	$7,975.00
		Total For Project 23 - Spill Prevention Clean-Up & Countermeasures			**$13,043,108.20**	**$14,364,447.18**
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	$14,956,035.32	$15,479,973.76
	02 - Steam Generation Plant	Manatee U2	31200	4.0%	$0.00	$14,743,192.81
		Total For Project 24 - Manatee Reburn			**$14,956,035.32**	**$30,223,166.57**
25 - PPE ESP Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.7%	$12,466,321.04	$13,082,737.27
	02 - Steam Generation Plant	PtEverglades U2	31200	6.1%	$15,173,737.09	$15,794,922.02
	02 - Steam Generation Plant	PtEverglades U1	31500	2.0%	$415,801.84	$418,393.78
	02 - Steam Generation Plant	PtEverglades U2	31500	2.1%	$634,855.66	$638,102.67
		Total For Project 25 - PPE ESP Technology			**$28,690,715.63**	**$29,934,155.74**
		Total For All Projects			**$105,534,576.38**	**$122,799,944.57**

APPENDIX I

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

JANUARY 2007 – DECEMBER 2007 ESTIMATED/ACTUAL TRUE-UP

KMD-2
DOCKET NO. 070007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT _____
PAGES 1-52

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 5
COMPANY Florida Power & Light
WITNESS K. M. Dubin (KMD-2)
DATE 11-06-07

Form 42-1E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up
for the Period January through December 2007

Line No.		
1	Over/(Under) Recovery for the Current Period (Form 42-2E, Page 2 of 2, Line 5)	($1,282,604)
2	Interest Provision (Form 42-2E, Page 2 of 2, Line 6)	$598,642
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 2008	($683,962)

( ) Reflects Underrecovery

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2007

Line No.		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June
1	ECRC Revenues (net of Revenue Taxes)	$1,983,736	$1,707,980	$1,689,491	$1,713,020	$1,891,211	$2,088,038
2	True-up Provision (Order No. PSC-06-0972-FOF-EI)	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,321,456	3,045,700	3,027,211	3,050,739	3,228,931	3,425,758
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5E, Line 9)	566,436	598,119	1,725,067	1,037,492	621,715	1,666,686
	b - Capital Investment Projects (Form 42-7E, Line 9)	1,629,758	1,759,288	1,787,917	1,814,741	1,861,056	1,964,793
	c - Total Jurisdictional ECRC Costs	2,196,194	2,357,407	3,512,984	2,852,233	2,482,771	3,631,479
5	Over/(Under) Recovery (Line 3 - Line 4c)	1,125,262	688,293	(485,773)	198,506	746,160	(205,721)
6	Interest Provision (Form 42-3E, Line 10)	76,826	75,201	70,111	63,925	60,412	56,104
7	Prior Periods True-Up to be (Collected)/Refunded in 2007	16,052,637	15,917,005	15,342,779	13,589,397	12,514,109	11,982,961
	a - Deferred True-Up from 2006 (Form 42-1A, Line 7)	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849
8	True-Up Collected /(Refunded) (See Line 2)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)
9	End of Period True-Up (Lines 5+6+7+7a+8)	17,480,854	16,906,628	15,153,246	14,077,958	13,546,810	12,059,473
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$17,480,854	$16,906,628	$15,153,246	$14,077,958	$13,546,810	$12,059,473

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2007

Line No.		Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$2,360,856	$2,374,903	$2,360,601	$2,216,793	$1,979,023	$1,994,994	$24,360,645
2	True-up Provision (Order No. PSC-06-0972-FOF-EI)	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720	16,052,637
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,698,576	3,712,622	3,698,320	3,554,512	3,316,742	3,332,713	40,413,282
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5E, Line 9)	1,435,857	1,427,308	1,966,801	2,431,111	2,162,843	2,290,581	17,930,015
	b - Capital Investment Projects (Form 42-7E, Line 9)	2,060,532	2,101,978	2,145,794	2,184,491	2,212,438	2,243,085	23,765,871
	c - Total Jurisdictional ECRC Costs	3,496,389	3,529,286	4,112,595	4,615,602	4,375,281	4,533,666	41,695,886
5	Over/(Under) Recovery (Line 3 - Line 4c)	202,187	183,336	(414,275)	(1,061,090)	(1,058,539)	(1,200,953)	(1,282,604)
6	Interest Provision (Form 42-3E, Line 10)	50,564	45,748	39,555	30,598	20,183	9,415	598,642
7	Prior Periods True-Up to be (Collected)/Refunded in 2007	10,495,624	9,410,655	8,302,020	6,589,581	4,221,370	1,845,295	16,052,637
	a - Deferred True-Up from 2006 (Form 42-1A, Line 7)	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849
8	True-Up Collected /(Refunded) (See Line 2)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(16,052,637)
9	End of Period True-Up (Lines 5+6+7+7a+8)	10,974,504	9,865,869	8,153,430	5,785,219	3,409,144	879,887	879,887
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	$10,974,504	$9,865,869	$8,153,430	$5,785,219	$3,409,144	$879,887	$879,887

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2007

Interest Provision (in Dollars)

Line No.		January	February	March	April	May	June
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$17,616,486	$17,480,854	$16,906,628	$15,153,246	$14,077,958	$13,546,810
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	17,404,028	16,831,427	15,083,135	14,014,033	13,486,398	12,003,369
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$35,020,514	$34,312,281	$31,989,763	$29,167,279	$27,564,356	$25,550,179
4	Average True-Up Amount (Line 3 x 1/2)	$17,510,257	$17,156,141	$15,994,882	$14,583,640	$13,782,178	$12,775,090
5	Interest Rate (First Day of Reporting Month)	5.27000%	5.26000%	5.26000%	5.26000%	5.26000%	5.26000%
6	Interest Rate (First Day of Subsequent Month)	5.26000%	5.26000%	5.26000%	5.26000%	5.26000%	5.28000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.53000%	10.52000%	10.52000%	10.52000%	10.52000%	10.54000%
8	Average Interest Rate (Line 7 x 1/2)	5.26500%	5.26000%	5.26000%	5.26000%	5.26000%	5.27000%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.43875%	0.43833%	0.43833%	0.43833%	0.43833%	0.43917%
10	Interest Provision for the Month (Line 4 x Line 9)	$76,826	$75,201	$70,111	$63,925	$60,412	$56,104

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2007

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)	$12,059,473	$10,974,504	$9,865,869	$8,153,430	$5,785,219	$3,409,144	$145,029,621
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	10,923,940	9,820,121	8,113,875	5,754,621	3,388,961	870,472	127,694,380
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$22,983,413	$20,794,625	$17,979,744	$13,908,051	$9,174,180	$4,279,616	$272,724,001
4	Average True-Up Amount (Line 3 x 1/2)	$11,491,707	$10,397,313	$8,989,872	$6,954,026	$4,587,090	$2,139,808	$136,362,001
5	Interest Rate (First Day of Reporting Month)	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	N/A
6	Interest Rate (First Day of Subsequent Month)	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.56000%	10.56000%	10.56000%	10.56000%	10.56000%	10.56000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.44000%	0.44000%	0.44000%	0.44000%	0.44000%	0.44000%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$50,564	$45,748	$39,555	$30,598	$20,183	$9,415	$598,642

Form 42-4E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
January 2007 - December 2007

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	$1,822,006	$1,951,100	($129,094)	-6.6%
3a	Continuous Emission Monitoring Systems-O&M	$685,667	$749,284	($63,617)	-8.5%
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	$2,239,772	$2,197,967	$41,805	1.9%
8a	Oil Spill Cleanup/Response Equipment-O&M	$211,821	$212,004	($183)	-0.1%
13	RCRA Corrective Action-O&M	$103,706	$100,000	$3,706	3.7%
14	NPDES Permit Fees-O&M	$124,400	$124,900	($500)	-0.4%
17a	Disposal of Noncontainerized Liquid Waste-O&M	$291,368	$269,000	$22,368	8.3%
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	$1,152,314	$1,147,220	$5,094	0.4%
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	$186,311	$78,150	$108,161	138.4%
19c	Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	($560,232)	($560,232)	$0	0.0%
20	Wastewater Discharge Elimination & Reuse	$0	$0	$0	0.0%
NA	Amortization of Gains on Sales of Emissions Allowances	($1,003,674)	($480,336)	($523,338)	109.0%
21	St. Lucie Turtle Net	$0	$0	$0	0.0%
22	Pipeline Integrity Management	$438,646	$839,000	($400,354)	-47.7%
23	SPCC-Spill Prevention, Control & Countermeasures	$313,753	$93,000	$220,753	237.4%
24	Manatee Reburn	$458,132	$500,000	($41,868)	-8.4%
25	Port Everglades ESP	$1,232,950	$2,105,100	($872,150)	-41.4%
26	UST Replacement/Removal	$6	$0	$6	100.0%
27	Lowest Quality Water Source	$368,233	$530,004	($161,771)	-30.5%
28	CWA 316(b) Phase II Rule	$1,325,259	$2,343,447	($1,018,188)	-43.4%
29	SCR Consumables	$259,889	$225,204	$34,685	15.4%
30	HBMP	$42,891	$24,996	$17,895	71.6%
31	CAIR Compliance	$376,055	$220,008	$156,047	70.9%
32	BART	$3,397	$0	$3,397	100.0%
33	St. Lucie Cooling Water System Inspection & Maintenance	$8,088,753	$0	$8,088,753	100.0%
2	Total O&M Activities	$18,161,423	$12,669,816	$5,491,607	43.3%
3	Recoverable Costs Allocated to Energy	$4,330,396	$5,735,829	($1,405,433)	-24.5%
4a	Recoverable Costs Allocated to CP Demand	$12,958,829	$6,066,883	$6,891,946	113.6%
4b	Recoverable Costs Allocated to GCP Demand	$872,198	$867,104	$5,094	0.6%

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-06-0972-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 2007 - December 2007

O&M Activities
(In Dollars)

Line #	Project #	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	166,075	18,529	165,175	153,827	165,175	165,175	833,956
	3a Continuous Emission Monitoring Systems-O&M	163,176	40,359	35,896	32,003	25,644	166,212	463,290
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	9,206	-7,914	1,311	7,249	27,965	365,710	403,527
	8a Oil Spill Cleanup/Response Equipment-O&M	17,555	13,168	13,401	37,789	13,510	5,498	100,921
	13 RCRA Corrective Action-O&M	0	12,483	6,363	0	0	0	18,846
	14 NPDES Permit Fees-O&M	124,400	0	0	0	0	0	124,400
	17a Disposal of Noncontainerized Liquid Waste-O&M	24,972	37,314	38,486	0	61,779	40,017	202,568
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	69,251	141,375	108,258	69,302	93,380	67,431	548,997
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	0	47,848	1,310	6,034	0	6	55,196
	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	-11,584	-11,584	-11,584	-11,584	-328,710	-89,804	-464,850
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0
	22 Pipeline Integrity Management	0	4,376	2,086	100,379	10,410	123,200	240,451
	23 SPCC - Spill Prevention, Control & Countermeasures	-6,847	9,790	10,915	31,425	87,884	22,687	155,854
	24 Manatee Rebum	31,615	13,440	77,504	38,268	-318	1,623	162,132
	25 PL Everglades ESP Technology	29,593	39,645	48,766	45,566	60,373	93,967	317,910
	26 UST Replacement/Removal	-5,504	5,510	0	0	0	0	6
	27 Lowest Quality Water Source	-840	0	39,064	0	22,911	62,816	123,951
	28 CWA 316(b) Phase II Rule	1,351	92,552	156,252	29,782	127,944	209,687	617,568
	29 SCR Consumables	6,805	4,260	26,029	8,456	27,653	44,389	117,592
	30 HBMP	1,504	2,831	5,483	2,229	2,229	1,415	15,691
	31 CAIR Compliance	-10,622	88,727	128,928	22,650	20,417	28,455	278,555
	32 BART	0	0	0	1,797	1,600	0	3,397
	34 St. Lucie Cooling Water System Inspection & Maintenance	10,351	98,730	940,461	522,530	255,948	426,940	2,254,960
	35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
2	Total of O&M Activities	$ 573,771	$ 604,751	$ 1,747,418	$ 1,051,016	$ 629,108	$ 1,688,738	$ 6,294,802
3	Recoverable Costs Allocated to Energy	$ 415,789	$ 245,743	$ 520,906	$ 327,441	$ 45,327	$ 453,737	$ 2,008,943
4a	Recoverable Costs Allocated to CP Demand	$ 112,074	$ 240,976	$ 1,141,597	$ 677,616	$ 513,744	$ 1,190,913	$ 3,876,920
4b	Recoverable Costs Allocated to GCP Demand	$ 45,908	$ 118,032	$ 84,915	$ 45,959	$ 70,037	$ 44,088	$ 408,939
5	Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	
6a	Retail CP Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$ 409,928	$ 242,279	$ 513,563	$ 322,825	$ 44,688	$ 447,341	$ 1,980,624
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 110,600	$ 237,808	$ 1,126,589	$ 668,708	$ 506,990	$ 1,175,257	$ 3,825,952
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 45,908	$ 118,032	$ 84,915	$ 45,959	$ 70,037	$ 44,088	$ 408,939
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 566,436	$ 598,119	$ 1,725,067	$ 1,037,492	$ 621,715	$ 1,666,686	$ 6,215,515

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 2007 - December 2007

O&M Activities
(In Dollars)

Line #	Project #	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	164,675	164,675	164,675	164,675	164,675	164,675	988,050	1,822,006			$1,822,006
	3a Continuous Emission Monitoring Systems-O&M	36,238	36,754	35,751	39,850	36,306	37,478	222,377	685,667			685,667
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	760,427	542,500	225,000	100,000	100,000	108,318	1,836,245	2,239,772	2,239,772		
	8a Oil Spill Cleanup/Response Equipment-O&M	15,150	25,150	15,150	15,150	25,150	15,150	110,900	211,821			211,821
	13 RCRA Corrective Action-O&M	15,000	0	30,000	0	25,000	14,860	84,860	103,706	103,706		
	14 NPDES Permit Fees-O&M							0	124,400	124,400		
	17a Disposal of Noncontainerized Liquid Waste-O&M	22,800	10,000	23,000	33,000	0	0	88,800	291,368			291,368
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	121,810	135,540	74,370	120,560	112,100	38,937	603,317	1,152,314		1,152,314	
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	28,857	0	32,258	0	70,000	0	131,115	186,311	171,979		14,332
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	-46,686	-46,686	-46,686	-46,686	-46,686	-46,686	-280,116	-560,232	(258,569)	(280,116)	(21,547)
	20 Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0	0	0		
	NA Amortization of Gains on Sales of Emissions Allowances	-89,804	-89,804	-89,804	-89,804	-89,804	-89,804	-538,824	-1,003,674			(1,003,674)
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0	0	0		
	22 Pipeline Integrity Management	22,115	176,080	0	0	0	0	198,195	438,646	438,646		
	23 SPCC - Spill Prevention, Control & Countermeasures	39,500	39,500	42,899	12,000	12,000	12,000	157,899	313,753	313,753		
	24 Manatee Reburn	31,000	41,000	41,000	61,000	61,000	61,000	296,000	458,132			458,132
	25 Pt. Everglades ESP Technology	95,784	110,784	101,562	435,662	76,032	95,196	915,040	1,232,950			1,232,950
	26 UST Replacement/Removal							0	6	6		
	27 Lowest Quality Water Source	24,583	24,583	24,583	24,583	24,583	121,367	244,282	368,233	368,233		
	28 CWA 316(b) Phase II Rule	133,243	77,847	86,410	101,616	85,930	222,645	707,691	1,325,259	1,325,259		
	29 SCR Consumables	23,542	37,292	23,524	17,292	23,542	17,105	142,297	259,889			259,889
	30 HBMP	1,700	6,700	1,700	1,700	13,700	1,700	27,200	42,891	42,891		
	31 CAIR Compliance	16,250	16,250	16,250	16,250	16,250	16,250	97,500	376,055			376,055
	32 BART	0	0	0	0	0	0	0	3,397			3,397
	34 St. Lucie Cooling Water System Inspection & Maintenance	37,793	137,000	1,191,000	1,456,000	1,481,000	1,531,000	5,833,793	8,088,753	8,088,753		
	35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0	0	0		
2	Total of O&M Activities	$1,453,977	$1,445,165	$1,992,642	$2,462,868	$2,190,778	$2,321,191	$11,866,621	$18,161,423	$ 12,958,829	$ 872,198	$ 4,330,396
3	Recoverable Costs Allocated to Energy	$ 316,059	$ 350,305	$ 331,784	$ 691,299	$ 316,740	$ 315,254	$ 2,321,452	$ 4,330,396			
4a	Recoverable Costs Allocated to CP Demand	$1,039,451	$ 982,663	$1,609,821	$1,674,352	$1,785,281	$1,990,343	$ 9,081,910	$12,958,829			
4b	Recoverable Costs Allocated to GCP Demand	$ 98,467	$ 112,197	$ 51,027	$ 97,217	$ 88,757	$ 15,594	$ 463,259	$ 872,198			
5	Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%					
6a	Retail CP Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	$ 311,604	$ 345,367	$ 327,116	$ 681,554	$ 312,275	$ 310,810	$ 2,288,726	$ 4,269,350			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$1,025,786	$ 969,744	$1,588,658	$1,652,340	$1,761,811	$1,964,177	$ 8,962,516	$12,788,468			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 98,467	$ 112,197	$ 51,027	$ 97,217	$ 88,757	$ 15,594	$ 463,259	$ 872,198			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,435,857	$1,427,308	$1,966,801	$2,431,111	$2,162,843	$2,290,581	$11,714,501	$17,930,016			

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 2007 - December 2007

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	$ 908,197	$ 931,745	$ (23,548)	-2.5%
3b	Continuous Emission Monitoring Systems-Capital	1,025,600	1,085,789	(60,189)	-5.5%
4b	Clean Closure Equivalency-Capital	3,990	4,148	(158)	-3.8%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	1,758,715	1,832,742	(74,027)	-4.0%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	1,600	1,674	(74)	-4.4%
8b	Oil Spill Cleanup/Response Equipment-Capital	73,475	71,718	1,757	2.4%
10	Relocate Storm Water Runoff-Capital	9,743	10,229	(486)	-4.8%
NA	SO2 Allowances-Negative Return on Investment	(186,275)	(254,313)	68,038	-26.8%
12	Scherer Discharge Pipeline-Capital	64,314	67,361	(3,047)	-4.5%
17b	Disposal of Noncontainerized Liquid Wate-Capital	0	0	0	0.0%
20	Wastewater Discharge Elimination & Reuse	245,826	257,983	(12,157)	-4.7%
21	St. Lucie Turtle Net	92,461	97,326	(4,865)	-5.0%
22	Pipeline Integrity Management	0	0	0	0.0%
23	SPCC-Spill Prevention, Control & Countermeasures	2,036,766	2,144,544	(107,778)	-5.0%
24	Manatee Reburn	4,886,546	5,019,067	(132,521)	-2.6%
25	Pt. Everglades ESP Technology	11,288,005	11,347,320	(59,315)	-0.5%
26	UST Replacement/Removal	-	67,554	(67,554)	-100.0%
31	CAIR Compliance	1,551,150	4,293,310	(2,742,160)	-63.9%
33	CAMR Compliance	340,077	1,594,640	(1,254,563)	-78.7%
35	Martin Plant Drinking Water System Compliance	0	0	0	100.0%
2	Total Investment Projects-Recoverable Costs	$ 24,100,190	$ 28,572,837	$ (4,472,647)	-15.7%
3	Recoverable Costs Allocated to Energy	$ 18,397,312	$ 18,932,935	$ (535,623)	-2.8%
4	Recoverable Costs Allocated to Demand	$ 5,702,878	$ 9,639,902	$ (3,937,024)	-40.8%

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-06-0972-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 2007 - December 2007

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	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	78,002	77,587	77,172	76,730	76,289	75,874	461,654
3b	Continuous Emission Monitoring Systems-Capital	86,718	86,399	86,110	85,787	85,483	85,248	515,745
4b	Clean Closure Equivalency-Capital	338	337	336	335	334	333	2,013
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	148,800	148,393	147,985	147,578	147,171	146,763	886,690
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	135	135	134	134	134	133	805
8b	Oil Spill Cleanup/Response Equipment-Capital	6,035	5,997	5,961	5,926	5,940	5,947	35,806
10	Relocate Storm Water Runoff-Capital	819	818	816	815	814	813	4,895
NA	SO2 Allowances-Negative Return on Investment	-19,422	-19,315	-19,208	-19,101	-17,527	-15,592	-110,165
12	Scherer Discharge Pipeline-Capital	5,417	5,407	5,396	5,386	5,375	5,365	32,346
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	20,671	20,637	20,604	20,570	20,536	20,502	123,520
21	St. Lucie Turtle Net	7,754	7,745	7,736	7,727	7,718	7,710	46,390
22	Pipeline Integrity Management	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	163,718	166,878	168,591	168,533	170,666	172,206	1,010,592
24	Manatee Reburn	382,830	381,974	381,117	380,166	379,142	405,708	2,310,937
25	Pt. Everglades ESP Technology	732,367	848,999	868,422	887,706	913,016	962,744	5,213,254
26	UST Removal / Replacement	0	0	0	0	0	0	0
31	CAIR Compliance	33,991	46,084	55,584	64,479	83,186	103,675	386,999
33	CAMR Compliance	4,539	6,005	6,353	7,537	8,988	15,031	48,453
35	Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$ 1,652,712	$ 1,784,080	$ 1,813,109	$ 1,840,308	$ 1,887,265	$ 1,992,460	$ 10,969,934
3	Recoverable Costs Allocated to Energy	$ 1,290,666	$ 1,407,062	$ 1,425,882	$ 1,444,290	$ 1,471,085	$ 1,550,788	$ 8,589,772
4	Recoverable Costs Allocated to Demand	$ 362,046	$ 377,018	$ 387,227	$ 396,018	$ 416,180	$ 441,672	$ 2,380,162
5	Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	
6	Retail Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,272,471	$ 1,387,227	$ 1,405,781	$ 1,423,929	$ 1,450,347	$ 1,528,927	$ 8,468,682
8	Jurisdictional Demand Recoverable Costs (C)	$ 357,287	$ 372,061	$ 382,136	$ 390,812	$ 410,709	$ 435,866	$ 2,348,871
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 1,629,758	$ 1,759,288	$ 1,787,917	$ 1,814,741	$ 1,861,056	$ 1,964,793	$ 10,817,553

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

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/actual True-up Amount for the Period
January 2007 - December 2007

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	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	75,460	75,045	74,631	74,217	73,802	73,388	446,543	908,197		908,197
3b	Continuous Emission Monitoring Systems-Capital	85,204	85,118	84,841	84,717	84,963	85,012	509,855	1,025,600		1,025,600
4b	Clean Closure Equivalency-Capital	332	331	330	329	328	327	1,977	3,990	3,683	307
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	146,356	145,949	145,541	145,134	144,726	144,319	872,025	1,758,715	1,623,429	135,286
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	133	133	133	132	132	132	795	1,600	1,477	123
8b	Oil Spill Cleanup/Response Equipment-Capital	6,168	6,307	6,270	6,233	6,195	6,496	37,669	73,475	67,823	5,652
10	Relocate Storm Water Runoff-Capital	811	810	809	807	806	805	4,848	9,743	8,994	749
NA	SO2 Allowances-Negative Return on Investment	-14,761	-13,931	-13,100	-12,270	-11,439	-10,609	-76,110	-186,275		-186,275
12	Scherer Discharge Pipeline-Capital	5,354	5,344	5,333	5,323	5,312	5,302	31,968	64,314	59,367	4,947
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	20,469	20,435	20,401	20,367	20,334	20,300	122,306	245,826	226,916	18,910
21	St. Lucie Turtle Net	7,701	7,692	7,683	7,674	7,665	7,656	46,071	92,461	85,349	7,112
22	Pipeline Integrity Management	0	0	0	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	171,987	171,604	171,221	170,837	170,454	170,071	1,026,174	2,036,766	1,880,092	156,674
24	Manatee Reburn	432,203	431,029	429,855	428,681	427,507	426,334	2,575,609	4,886,546		4,886,546
25	Pt. Everglades ESP Technology	1,004,688	1,014,292	1,016,555	1,015,791	1,013,125	1,010,300	6,074,751	11,288,005		11,288,005
26	UST Removal / Replacement	0	0	0	0	0	0	0	0	0	0
31	CAIR Compliance	125,719	154,151	185,167	211,672	231,400	256,042	1,164,151	1,551,150	1,431,831	119,319
33	CAMR Compliance	21,719	27,243	40,287	55,526	68,180	78,669	291,624	340,077	313,917	26,160
35	Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$ 2,089,543	$ 2,131,552	$ 2,175,957	$ 2,215,170	$ 2,243,490	$ 2,274,544	$ 13,130,256	$ 24,100,190	$ 5,702,878	$ 18,397,312
3	Recoverable Costs Allocated to Energy	$ 1,621,775	$ 1,633,091	$ 1,637,642	$ 1,639,139	$ 1,638,384	$ 1,637,511	$ 9,807,541	$ 18,397,312		
4	Recoverable Costs Allocated to Demand	$ 467,768	$ 498,461	$ 538,315	$ 576,031	$ 605,106	$ 637,033	$ 3,322,715	$ 5,702,878		
5	Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%				
6	Retail Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%				
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,598,913	$ 1,610,070	$ 1,614,556	$ 1,616,032	$ 1,615,287	$ 1,614,427	$ 9,669,285	$ 18,137,967		
8	Jurisdictional Demand Recoverable Costs (C)	$ 461,619	$ 491,908	$ 531,238	$ 568,459	$ 597,151	$ 628,658	$ 3,279,033	$ 5,627,904		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 2,060,532	$ 2,101,978	$ 2,145,794	$ 2,184,491	$ 2,212,438	$ 2,243,085	$ 12,948,318	$ 23,765,871		

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

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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					$35,815			$35,815
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,509,209	17,509,209	17,509,209	17,509,209	17,473,393	17,473,393	17,473,393	n/a
3.	Less: Accumulated Depreciation (C)	13,903,927	13,948,794	13,993,662	14,038,529	14,047,554	14,092,367	14,137,181	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$3,605,282	$3,560,414	$3,515,547	$3,470,680	$3,425,840	$3,381,026	$3,336,213	n/a
6.	Average Net Investment		3,582,848	3,537,981	3,493,114	3,448,260	3,403,433	3,358,619	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		27,531	27,186	26,842	26,497	26,153	25,808	160,017
	b. Debt Component (Line 6 x 1.8767% x 1/12)		5,603	5,533	5,463	5,393	5,323	5,253	32,567
8.	Investment Expenses								
	a. Depreciation (E)		44,867	44,867	44,867	44,840	44,813	44,813	269,069
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$78,002	$77,587	$77,172	$76,730	$76,289	$75,874	$461,654

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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								$35,815
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	n/a
3.	Less: Accumulated Depreciation (C)	14,137,181	14,181,994	14,226,808	14,271,621	14,316,435	14,361,248	14,406,061	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$3,336,213	$3,291,399	$3,246,586	$3,201,772	$3,156,959	$3,112,145	$3,067,332	n/a
6.	Average Net Investment		3,313,806	3,268,993	3,224,179	3,179,366	3,134,552	3,089,739	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		25,464	25,119	24,775	24,431	24,086	23,742	307,635
	b. Debt Component (Line 6 x 1.8767% x 1/12)		5,183	5,112	5,042	4,972	4,902	4,832	62,611
8.	Investment Expenses								
	a. Depreciation (E)		44,813	44,813	44,813	44,813	44,813	44,813	537,950
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$75,460	$75,045	$74,631	$74,217	$73,802	$73,388	$908,197

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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				($2,635)	$3,268		$18,307	$18,939
	c. Retirements					$3,478		$32,522	$36,000
	d. Other (A)								$0
2.	Plant-In-Service/Depreciation Base (B)	$12,613,846	12,613,846	12,613,846	12,611,211	12,611,001	12,611,001	12,596,785	0
3.	Less: Accumulated Depreciation (C)	6,949,745	6,984,241	7,018,736	7,053,274	7,084,327	7,118,859	7,120,868	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$5,664,101	$5,629,605	$5,595,110	$5,557,937	$5,526,674	$5,492,142	$5,475,917	n/a
6.	Average Net Investment		5,646,853	5,612,358	5,576,523	5,542,305	5,509,408	5,484,030	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		43,391	43,126	42,851	42,588	42,335	42,140	256,432
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,831	8,777	8,721	8,668	8,616	8,577	52,190
8.	Investment Expenses								
	a. Depreciation (E)		34,496	34,496	34,537	34,531	34,531	34,532	207,123
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$86,718	$86,399	$86,110	$85,787	$85,483	$85,248	$515,745

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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		$34,000	$7,000		$28,000	$56,000		$143,939
	c. Retirements								$36,000
	d. Other (A)								$0
2.	Plant-In-Service/Depreciation Base (B)	$12,596,785	12,630,785	12,637,785	12,637,785	12,665,785	12,721,785	12,721,785	n/a
3.	Less: Accumulated Depreciation (C)	7,120,868	7,155,433	7,190,042	7,224,662	7,259,349	7,294,215	7,329,194	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$5,475,917	$5,475,352	$5,447,743	$5,413,123	$5,406,436	$5,427,570	$5,392,591	n/a
6.	Average Net Investment		5,475,635	5,461,548	5,430,433	5,409,780	5,417,003	5,410,080	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		42,076	41,967	41,728	41,570	41,625	41,572	506,970
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,563	8,541	8,493	8,460	8,472	8,461	103,181
8.	Investment Expenses								
	a. Depreciation (E)		34,565	34,609	34,620	34,687	34,867	34,979	415,450
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$85,204	$85,118	$84,841	$84,717	$84,963	$85,012	$1,025,600

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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)	34,252	34,362	34,473	34,584	34,695	34,806	34,916	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$24,614	$24,504	$24,393	$24,282	$24,171	$24,060	$23,950	n/a
6.	Average Net Investment		24,559	24,448	24,337	24,227	24,116	24,005	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		189	188	187	186	185	184	1,120
	b. Debt Component (Line 6 x 1.8767% x 1/12)		38	38	38	38	38	38	228
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$338	$337	$336	$335	$334	$333	$2,013

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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)	34,916	35,027	35,138	35,249	35,360	35,470	35,581	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$23,950	$23,839	$23,728	$23,617	$23,506	$23,396	$23,285	n/a
6.	Average Net Investment		23,894	23,783	23,673	23,562	23,451	23,340	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		184	183	182	181	180	179	2,208
	b. Debt Component (Line 6 x 1.8767% x 1/12)		37	37	37	37	37	37	449
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	1,330
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$332	$331	$330	$329	$328	$327	$3,990

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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)	$13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	n/a
3.	Less: Accumulated Depreciation (C)	2,201,151	2,245,197	2,289,244	2,333,290	2,377,337	2,421,383	2,465,430	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,349,067	$11,305,020	$11,260,974	$11,216,927	$11,172,881	$11,128,834	$11,084,788	n/a
6.	Average Net Investment		11,327,044	11,282,997	11,238,951	11,194,904	11,150,858	11,106,811	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		87,039	86,700	86,362	86,024	85,685	85,347	517,157
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17,715	17,646	17,577	17,508	17,439	17,370	105,254
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,046	44,046	44,046	44,046	44,046	264,279
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$148,800	$148,393	$147,985	$147,578	$147,171	$146,763	$886,690

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	n/a
3.	Less: Accumulated Depreciation (C)	2,465,430	2,509,476	2,553,523	2,597,569	2,641,616	2,685,662	2,729,709	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,084,788	$11,040,742	$10,996,695	$10,952,649	$10,908,602	$10,864,556	$10,820,509	n/a
6.	Average Net Investment		11,062,765	11,018,718	10,974,672	10,930,625	10,886,579	10,842,532	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		85,008	84,670	84,331	83,993	83,654	83,316	1,022,128
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17,301	17,232	17,163	17,095	17,026	16,957	208,028
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,046	44,046	44,046	44,046	44,046	528,558
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$146,356	$145,949	$145,541	$145,134	$144,726	$144,319	$1,758,715

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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)	19,782	19,813	19,844	19,875	19,906	19,937	19,968	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,248	$11,217	$11,186	$11,155	$11,124	$11,093	$11,062	n/a
6.	Average Net Investment		11,232	11,201	11,170	11,139	11,108	11,077	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		86	86	86	86	85	85	514
	b. Debt Component (Line 6 x 1.8767% x 1/12)		18	18	17	17	17	17	105
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	186
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$135	$135	$134	$134	$134	$133	$805

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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)	19,968	19,999	20,030	20,061	20,092	20,123	20,154	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,062	$11,031	$11,000	$10,969	$10,938	$10,907	$10,876	n/a
6.	Average Net Investment		11,046	11,015	10,984	10,953	10,922	10,891	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		85	85	84	84	84	84	1,020
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17	17	17	17	17	17	208
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	372
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$133	$133	$133	$132	$132	$132	$1,600

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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		$1,997	$0	$0	$0	$531	$7,691	$10,219
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$342,502	344,499	344,499	344,499	344,499	345,030	352,721	n/a
3.	Less: Accumulated Depreciation (C)	106,058	109,915	113,760	117,605	121,451	125,343	129,241	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$236,445	$234,585	$230,739	$226,894	$223,049	$219,687	$223,480	n/a
6.	Average Net Investment		235,515	232,662	228,817	224,971	221,368	221,584	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,810	1,788	1,758	1,729	1,701	1,703	10,488
	b. Debt Component (Line 6 x 1.8767% x 1/12)		368	364	358	352	346	347	2,135
8.	Investment Expenses								
	a. Depreciation (E)		3,857	3,845	3,845	3,845	3,893	3,897	23,183
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$6,035	$5,997	$5,961	$5,926	$5,940	$5,947	$35,806

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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		$28,000					$32,000	$70,219
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$352,721	380,721	380,721	380,721	380,721	380,721	412,721	n/a
3.	Less: Accumulated Depreciation (C)	129,241	133,231	137,268	141,306	145,343	149,380	153,608	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$223,480	$247,490	$243,453	$239,415	$235,378	$231,341	$259,113	n/a
6.	Average Net Investment		235,485	245,471	241,434	237,397	233,360	245,227	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,810	1,886	1,855	1,824	1,793	1,884	21,541
	b. Debt Component (Line 6 x 1.8767% x 1/12)		368	384	378	371	365	384	4,384
8.	Investment Expenses								
	a. Depreciation (E)		3,990	4,037	4,037	4,037	4,037	4,228	47,550
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$6,168	$6,307	$6,270	$6,233	$6,195	$6,496	$73,475

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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)	44,037	44,174	44,311	44,449	44,586	44,724	44,861	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$73,757	$73,620	$73,483	$73,345	$73,208	$73,070	$72,933	n/a
6.	Average Net Investment		73,689	73,551	73,414	73,277	73,139	73,002	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		566	565	564	563	562	561	3,382
	b. Debt Component (Line 6 x 1.8767% x 1/12)		115	115	115	115	114	114	688
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	825
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$819	$818	$816	$815	$814	$813	$4,895

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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)	44,861	44,998	45,136	45,273	45,411	45,548	45,686	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$72,933	$72,796	$72,658	$72,521	$72,383	$72,246	$72,108	n/a
6.	Average Net Investment		72,864	72,727	72,589	72,452	72,315	72,177	
7.	*Return on Average Net Investment*								
	a. Equity Component grossed up for taxes (D)		560	559	558	557	556	555	6,725
	b. Debt Component (Line 6 x 1.8767% x 1/12)		114	114	114	113	113	113	1,369
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	1,649
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$811	$810	$809	$807	$806	$805	$9,743

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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)	401,043	402,181	403,320	404,459	405,598	406,736	407,875	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$463,217	$462,079	$460,940	$459,801	$458,662	$457,524	$456,385	n/a
6.	Average Net Investment		462,648	461,509	460,370	459,232	458,093	456,954	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,555	3,546	3,538	3,529	3,520	3,511	21,199
	b. Debt Component (Line 6 x 1.8767% x 1/12)		724	722	720	718	716	715	4,315
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	6,833
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,417	$5,407	$5,396	$5,386	$5,375	$5,365	$32,346

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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)	407,875	409,014	410,153	411,291	412,430	413,569	414,708	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$456,385	$455,246	$454,107	$452,969	$451,830	$450,691	$449,552	n/a
6.	Average Net Investment		455,815	454,677	453,538	452,399	451,260	450,122	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,503	3,494	3,485	3,476	3,468	3,459	42,083
	b. Debt Component (Line 6 x 1.8767% x 1/12)		713	711	709	708	706	704	8,565
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	13,665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,354	$5,344	$5,333	$5,323	$5,312	$5,302	$64,314

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% 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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	519,211	522,860	526,508	530,157	533,806	537,454	541,103	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,842,451	$1,838,802	$1,835,153	$1,831,505	$1,827,856	$1,824,207	$1,820,559	n/a
6.	Average Net Investment		1,840,627	1,836,978	1,833,329	1,829,680	1,826,032	1,822,383	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		14,144	14,116	14,088	14,060	14,032	14,003	84,442
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,879	2,873	2,867	2,861	2,856	2,850	17,186
8.	Investment Expenses								
	a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	21,892
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$20,671	$20,637	$20,604	$20,570	$20,536	$20,502	$123,520

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	$541,103	544,752	548,401	552,049	555,698	559,347	562,995	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,820,559	$1,816,910	$1,813,261	$1,809,612	$1,805,964	$1,802,315	$1,798,666	n/a
6.	Average Net Investment		1,818,734	1,815,086	1,811,437	1,807,788	1,804,139	1,800,491	
7.	Return on Average Net Investment								
	Equity Component grossed up for taxes (D)		13,975	13,947	13,919	13,891	13,863	13,835	167,874
	Debt Component (Line 6 x 1.8767% x 1/12)		2,844	2,839	2,833	2,827	2,822	2,816	34,166
8.	Investment Expenses								
	a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	43,785
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$20,469	$20,435	$20,401	$20,367	$20,334	$20,300	$245,826

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$828,789	828,789	828,789	828,789	828,789	828,789	828,789	n/a
3.	Less: Accumulated Depreciation (C)	94,388	95,355	96,322	97,289	98,256	99,223	100,190	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$734,401	$733,434	$732,467	$731,500	$730,533	$729,566	$728,599	n/a
6.	Average Net Investment		733,917	732,950	731,983	731,017	730,050	729,083	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		5,640	5,632	5,625	5,617	5,610	5,602	33,726
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,148	1,146	1,145	1,143	1,142	1,140	6,864
8.	Investment Expenses								
	a. Depreciation (E)		967	967	967	967	967	967	5,802
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,754	$7,745	$7,736	$7,727	$7,718	$7,710	$46,390

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$828,789	828,789	828,789	828,789	828,789	828,789	828,789	n/a
3.	Less: Accumulated Depreciation (C)	$100,190	101,157	102,124	103,091	104,057	105,024	105,991	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$728,599	$727,632	$726,665	$725,698	$724,732	$723,765	$722,798	n/a
6.	Average Net Investment		728,116	727,149	726,182	725,215	724,248	723,281	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		5,595	5,588	5,580	5,573	5,565	5,558	67,184
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,139	1,137	1,136	1,134	1,133	1,131	13,674
8.	Investment Expenses								
	a. Depreciation (E)		967	967	967	967	967	967	11,603
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,701	$7,692	$7,683	$7,674	$7,665	$7,656	$92,461

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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		$241,305	$360,467	$31,078	$28,672	$382,656	$30,426	$1,074,604
	c. Retirements								
	d. Other (A)						$2,738		
2.	Plant-In-Service/Depreciation Base (B)	$14,364,448	14,605,753	14,966,220	14,997,298	15,025,970	15,408,626	15,439,052	n/a
3.	Less: Accumulated Depreciation (C)	1,053,048	1,092,729	1,133,158	1,173,864	1,214,612	1,258,722	1,300,119	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$13,311,400	$13,513,024	$13,833,062	$13,823,434	$13,811,358	$14,149,904	$14,138,932	n/a
6.	Average Net Investment		13,412,212	13,673,043	13,828,248	13,817,396	13,980,631	14,144,418	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		103,062	105,066	106,259	106,175	107,430	108,688	636,679
	b. Debt Component (Line 6 x 1.8767% x 1/12)		20,976	21,384	21,626	21,609	21,865	22,121	129,580
8.	Investment Expenses								
	a. Depreciation (E)		39,681	40,429	40,706	40,749	41,372	41,397	244,334
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$163,718	$166,878	$168,591	$168,533	$170,666	$172,206	$1,010,592

Notes:

(A) Reserve Transfer/Adj.
(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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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								$1,074,604
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$15,439,052	15,439,052	15,439,052	15,439,052	15,439,052	15,439,052	15,439,052	n/a
3.	Less: Accumulated Depreciation (C)	$1,300,119	1,341,540	1,382,960	1,424,380	1,465,800	1,507,220	1,548,640	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$14,138,932	$14,097,512	$14,056,092	$14,014,672	$13,973,252	$13,931,832	$13,890,412	n/a
6.	Average Net Investment		14,118,222	14,076,802	14,035,382	13,993,962	13,952,542	13,911,122	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		108,487	108,169	107,850	107,532	107,214	106,895	1,282,826
	b. Debt Component (Line 6 x 1.8767% x 1/12)		22,080	22,015	21,950	21,885	21,821	21,756	261,086
8.	Investment Expenses								
	a. Depreciation (E)		41,420	41,420	41,420	41,420	41,420	41,420	492,854
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$171,987	$171,604	$171,221	$170,837	$170,454	$170,071	$2,036,766

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$11,713	$15,650	$11,534	$654	$0	$4,275,321	$4,314,872
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$30,223,167	30,234,879	30,250,530	30,262,064	30,262,718	30,262,718	34,538,039	n/a
3.	Less: Accumulated Depreciation (C)	789,407	900,491	1,011,620	1,122,794	1,233,989	1,345,184	1,464,242	n/a
4.	CWIP - Non Interest Bearing		0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$29,433,759	$29,334,388	$29,238,910	$29,139,270	$29,028,729	$28,917,533	$33,073,796	n/a
6.	Average Net Investment		29,384,074	29,286,649	29,189,090	29,083,999	28,973,131	30,995,665	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		225,792	225,044	224,294	223,486	222,634	238,176	1,359,426
	b. Debt Component (Line 6 x 1.8767% x 1/12)		45,954	45,802	45,649	45,485	45,312	48,475	276,677
8.	Investment Expenses								
	a. Depreciation (E)		111,083	111,129	111,174	111,195	111,196	119,058	674,835
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$382,830	$381,974	$381,117	$380,166	$379,142	$405,708	$2,310,937

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$4,314,872
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$34,538,039	34,538,039	34,538,039	34,538,039	34,538,039	34,538,039	34,538,039	n/a
3.	Less: Accumulated Depreciation (C)	$1,464,242	1,591,163	1,718,083	1,845,003	1,971,923	2,098,843	2,225,764	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$33,073,796	$32,946,876	$32,819,956	$32,693,036	$32,566,116	$32,439,195	$32,312,275	n/a
6.	Average Net Investment		33,010,336	32,883,416	32,756,496	32,629,576	32,502,655	32,375,735	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		253,657	252,682	251,706	250,731	249,756	248,781	$2,866,739
	b. Debt Component (Line 6 x 1.8767% x 1/12)		51,625	51,427	51,228	51,030	50,831	50,633	$583,452
8.	Investment Expenses								
	a. Depreciation (E)		126,920	126,920	126,920	126,920	126,920	126,920	$1,436,356
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$432,203	$431,029	$429,855	$428,681	$427,507	$426,334	$4,886,546

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$4,952,476	$1,595,352	$2,248,017	$2,100,583	$1,249,385	$0	$12,145,814
	b. Clearings to Plant		24,971,594	572,501	42,942	170,427	1,781,492	$22,004,185	$49,543,141
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$29,934,156	54,905,750	55,478,251	55,521,194	55,691,620	57,473,112	79,477,297	n/a
3.	Less: Accumulated Depreciation (C)	2,579,857	2,770,709	2,998,123	3,226,451	3,455,081	3,686,633	3,952,945	n/a
4.	CWIP - Non Interest Bearing	23,512,393	14,106,905	15,702,257	17,950,275	20,050,858	21,300,243	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$50,866,692	$66,241,946	$68,182,385	$70,245,017	$72,287,397	$75,086,722	$75,524,351	n/a
6.	Average Net Investment		58,554,319	67,212,166	69,213,701	71,266,207	73,687,059	75,305,537	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		449,941	516,470	531,850	547,621	566,224	578,660	3,190,766
	b. Debt Component (Line 6 x 1.8767% x 1/12)		91,574	105,114	108,244	111,454	115,240	117,772	649,399
8.	Investment Expenses								
	a. Depreciation (E)		190,851	227,415	228,328	228,630	231,552	266,312	1,373,088
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$732,367	$848,999	$868,422	$887,706	$913,016	$962,744	$5,213,254

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$12,145,814
	b. Clearings to Plant		$1,506,362	$511,848	$319,212	$26,000	$0	$0	$51,906,563
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$79,477,297	80,983,659	81,495,507	81,814,719	81,840,719	81,840,719	81,840,719	n/a
3.	Less: Accumulated Depreciation (C)	$3,952,945	4,253,603	4,557,326	4,862,285	5,167,705	5,473,164	5,778,624	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$75,524,351	$76,730,056	$76,938,180	$76,952,434	$76,673,014	$76,367,554	$76,062,095	n/a
6.	Average Net Investment		76,127,204	76,834,118	76,945,307	76,812,724	76,520,284	76,214,825	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		584,974	590,406	591,261	590,242	587,995	585,647	$6,721,291
	b. Debt Component (Line 6 x 1.8767% x 1/12)		119,057	120,162	120,336	120,129	119,671	119,194	$1,367,948
8.	Investment Expenses								
	a. Depreciation (E)		300,657	303,724	304,958	305,420	305,459	305,459	$3,198,766
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,004,688	$1,014,292	$1,016,555	$1,015,791	$1,013,125	$1,010,300	$11,288,005

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% 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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(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		$1,140,561	$1,474,564	$579,965	$1,343,744	$2,701,874	$1,729,136	$8,969,845
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	3,105,197	4,245,758	5,720,322	6,300,288	7,644,032	10,345,905	12,075,042	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,105,197	$4,245,758	$5,720,322	$6,300,288	$7,644,032	$10,345,905	$12,075,042	n/a
6.	Average Net Investment		3,675,477	4,983,040	6,010,305	6,972,160	8,994,968	11,210,473	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		28,243	38,291	46,184	53,575	69,119	86,143	321,555
	b. Debt Component (Line 6 x 1.8767% x 1/12)		5,748	7,793	9,400	10,904	14,067	17,532	65,444
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)		$33,991	$46,084	$55,584	$64,479	$83,186	$103,675	$386,999

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$3,037,978	$3,110,808	$3,596,768	$2,135,158	$2,131,205	$3,104,216	$26,085,978
	b. Clearings to Plant		$0	$0	$0	$0	$0	$396,999	$396,999
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	396,999	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	436	n/a
4.	CWIP - Non Interest Bearing	$12,075,042	15,113,020	18,223,828	21,820,596	23,955,754	26,086,959	28,794,176	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$12,075,042	$15,113,020	$18,223,828	$21,820,596	$23,955,754	$26,086,959	$29,190,739	n/a
6.	Average Net Investment		13,594,031	16,668,424	20,022,212	22,888,175	25,021,356	27,638,849	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		104,459	128,083	153,854	175,877	192,268	212,382	$1,288,477
	b. Debt Component (Line 6 x 1.8767% x 1/12)		21,260	26,068	31,313	35,795	39,131	43,225	$262,237
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	436	$436
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$125,719	$154,151	$185,167	$211,672	$231,400	$256,042	$1,551,150

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(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		$258,550	$58,605	$16,677	$239,395	$74,270	$1,232,705	$1,880,201
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	361,479	620,029	678,634	695,311	934,706	1,008,976	2,241,681	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$361,479	$620,029	$678,634	$695,311	$934,706	$1,008,976	$2,241,681	n/a
6.	Average Net Investment		490,754	649,331	686,972	815,008	971,841	1,625,328	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,771	4,990	5,279	6,263	7,468	12,489	40,259
	b. Debt Component (Line 6 x 1.8767% x 1/12)		767	1,016	1,074	1,275	1,520	2,542	8,194
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)		$4,539	$6,005	$6,353	$7,537	$8,988	$15,031	$48,453

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(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		$213,532	$981,085	$1,839,993	$1,455,464	$1,281,128	$987,378	$8,638,781
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$2,241,681	2,455,213	3,436,298	5,276,291	6,731,755	8,012,883	9,000,261	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,241,681	$2,455,213	$3,436,298	$5,276,291	$6,731,755	$8,012,883	$9,000,261	n/a
6.	Average Net Investment		2,348,447	2,945,755	4,356,294	6,004,023	7,372,319	8,506,572	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		18,046	22,636	33,474	46,136	56,650	65,366	$282,567
	b. Debt Component (Line 6 x 1.8767% x 1/12)		3,673	4,607	6,813	9,390	11,530	13,304	$57,509
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)		$21,719	$27,243	$40,287	$55,526	$68,180	$78,669	$340,077

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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Drinking Water System Complianace (Project No. 35)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	n/a
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	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% 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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Drinking Water System Compliance (Project No. 35)
(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								$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	*Return on Average Net Investment*								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% 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 41-43.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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	(2,105,917)	(2,094,333)	(2,082,750)	(2,071,166)	(2,059,583)	(1,730,873)	(1,641,069)		
2	Total Working Capital	($2,105,917)	($2,094,333)	($2,082,750)	($2,071,166)	($2,059,583)	($1,730,873)	($1,641,069)		
3	Average Net Working Capital Balance		(2,100,125)	(2,088,542)	(2,076,958)	(2,065,374)	(1,895,228)	(1,685,971)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(16,138)	(16,049)	(15,960)	(15,871)	(14,563)	(12,955)	(91,535)	
	b Debt Component (Line 6 x 1.87670% x 1/12)		(3,284)	(3,266)	(3,248)	(3,230)	(2,964)	(2,637)	(18,630)	
5	Total Return Component		($19,422)	($19,315)	($19,208)	($19,101)	($17,527)	($15,592)	($110,165)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(11,584)	(11,584)	(11,584)	(11,584)	(328,710)	(89,804)	(464,848)	
	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)		($11,584)	($11,584)	($11,584)	($11,584)	($328,710)	($89,804)	($464,848)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(7,839)	(7,731)	(7,624)	(7,517)	311,183	74,212		
	a Recoverable Costs Allocated to Energy		(7,839)	(7,731)	(7,624)	(7,517)	311,183	74,212		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%		
10	Demand Jurisdictional Factor		98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%		
11	Retail Energy-Related Recoverable Costs (B)		(7,724)	(7,618)	(7,513)	(7,407)	306,619	73,123	349,482	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($7,724)	($7,618)	($7,513)	($7,407)	$306,619	$73,123	$349,482	

Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% 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 2007

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	(1,641,069)	(1,551,265)	(1,461,461)	(1,371,658)	(1,281,854)	(1,192,050)	(1,102,246)		
2	Total Working Capital	($1,641,069)	($1,551,265)	($1,461,461)	($1,371,658)	($1,281,854)	($1,192,050)	($1,102,246)		
3	Average Net Working Capital Balance		(1,596,167)	(1,506,363)	(1,416,560)	(1,326,756)	(1,236,952)	(1,147,148)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(12,265)	(11,575)	(10,885)	(10,195)	(9,505)	(8,815)	(154,776)	
	b Debt Component (Line 6 x 1.6698% x 1/12)		(2,496)	(2,356)	(2,215)	(2,075)	(1,934)	(1,794)	(31,501)	
5	Total Return Component		($14,761)	($13,931)	($13,100)	($12,270)	($11,439)	($10,609)	($186,276)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(1,003,670)	
	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)		($89,804)	($89,804)	($89,804)	($89,804)	($89,804)	($89,804)	($1,003,670)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		$75,042	$75,873	$76,703	$77,534	$78,364	$79,195		
	a Recoverable Costs Allocated to Energy		75,042	75,873	76,703	77,534	78,364	79,195		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%		
10	Demand Jurisdictional Factor		98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%		
11	Retail Energy-Related Recoverable Costs (B)		73,942	74,760	75,578	76,397	77,215	78,033	805,407	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		$73,942	$74,760	$75,578	$76,397	$77,215	$78,033	$805,407	

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 5.6640% reflects an 11.75% 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
2007 Annual Capital Depreciation Schedule

Project Number	Function	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Actual 12/31/2006 Plant In Service	Estimated 12/31/2007 Plant In Service
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.7%	2,700,574.97	2,700,574.97
	02 - Steam Generation Plant	PtEverglades U2	31200	6.1%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	Riviera U3	31200	1.7%	3,815,802.70	3,815,802.70
	02 - Steam Generation Plant	Riviera U4	31200	1.4%	3,246,925.80	3,246,925.80
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.0%	2,925,027.84	2,925,027.84
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.8%	2,451,904.92	2,416,089.59
		Total For Project 02 - Low NOX Burner Technology			17,509,208.50	17,473,393.17
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	59,227.10	59,227.10
	02 - Steam Generation Plant	CapeCanaveral Comm	31200	1.3%	30,059.25	30,059.25
	02 - Steam Generation Plant	CapeCanaveral U1	31200	1.4%	494,606.87	494,606.87
	02 - Steam Generation Plant	CapeCanaveral U2	31200	1.1%	511,705.24	511,705.24
	02 - Steam Generation Plant	Cutler Comm	31100	0.0%	64,883.87	64,883.87
	02 - Steam Generation Plant	Cutler Comm	31200	0.5%	27,351.73	27,351.73
	02 - Steam Generation Plant	Cutler U5	31200	0.1%	312,722.43	319,722.43
	02 - Steam Generation Plant	Cutler U6	31200	1.0%	314,129.96	321,129.96
	02 - Steam Generation Plant	Manatee Comm	31200	14.1%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	4.1%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	472,570.03	472,570.03
	02 - Steam Generation Plant	Manatee U2	31100	4.1%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	4.0%	508,734.36	508,734.36
	02 - Steam Generation Plant	Martin Comm	31200	4.1%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	1.5%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	1.8%	521,075.17	521,075.17
	02 - Steam Generation Plant	Martin U2	31100	1.5%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	1.5%	519,484.96	519,484.96
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	127,911.34	127,911.34
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.2%	61,620.47	61,620.47
	02 - Steam Generation Plant	PtEverglades U1	31200	6.7%	453,661.22	453,661.22
	02 - Steam Generation Plant	PtEverglades U2	31200	6.1%	475,113.36	475,113.36
	02 - Steam Generation Plant	PtEverglades U3	31200	4.0%	503,968.62	503,968.62
	02 - Steam Generation Plant	PtEverglades U4	31200	3.6%	512,809.90	532,809.90
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	60,973.18	60,973.18
	02 - Steam Generation Plant	Riviera Comm	31200	0.4%	29,117.75	13,315.76
	02 - Steam Generation Plant	Riviera U3	31200	1.7%	449,392.38	449,392.38
	02 - Steam Generation Plant	Riviera U4	31200	1.4%	433,421.96	433,421.96
	02 - Steam Generation Plant	Sanford U3	31100	4.0%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	3.6%	431,831.34	438,831.34
	02 - Steam Generation Plant	Scherer U4	31200	1.9%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.1%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.0%	66,188.18	66,188.18
	02 - Steam Generation Plant	SJRPP U1	31200	2.2%	107,594.02	107,594.02
	02 - Steam Generation Plant	SJRPP U2	31200	2.3%	107,562.94	107,562.94
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.3%	59,056.19	59,056.19
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31200	2.1%	29,110.85	29,110.85
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.0%	546,534.15	546,534.15
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.8%	505,638.44	505,638.44
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.1%	58,859.79	58,859.79
	05 - Other Generation Plant	FtLauderdale Comm	34500	4.1%	34,502.21	34,502.21
	05 - Other Generation Plant	FtLauderdale U4	34300	5.0%	461,080.14	476,456.39
	05 - Other Generation Plant	FtLauderdale U5	34300	3.7%	471,313.47	485,313.47
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.5%	106,324.08	106,324.08
	05 - Other Generation Plant	FtMyers U3 CC	34300	5.6%	2,635.22	0.00
	05 - Other Generation Plant	Martin U3	34300	5.8%	431,927.00	445,927.00
	05 - Other Generation Plant	Martin U4	34300	5.7%	421,026.31	435,026.31
	05 - Other Generation Plant	Martin U8	34300	5.5%	25,657.00	25,657.00
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.1%	82,857.82	82,857.82
	05 - Other Generation Plant	FtLauderdale Comm	34300	6.3%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	5.2%	335,440.55	349,440.55
	05 - Other Generation Plant	Putnam U2	34300	5.4%	368,844.07	382,844.07
	05 - Other Generation Plant	Sanford U4	34300	5.6%	45,032.12	95,501.38
	05 - Other Generation Plant	Sanford U5	34300	5.7%	104,111.16	53,641.90
		Total For Project 03 - Continuous Emission Monitoring			12,613,845.87	12,721,784.91

Florida Power & Light Company
Environmental Cost Recovery Clause
2007 Annual Capital Depreciation Schedule

Project Number	Function	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Actual 12/31/2006 Plant In Service	Estimated 12/31/2007 Plant In Service
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	17,254.20	17,254.20
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	19,812.30	19,812.30
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.3%	21,799.28	21,799.28
	Total For Project 04 - Clean Closure Equivalency Demonstration				58,865.78	58,865.78
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	901,636.88	901,636.88
	02 - Steam Generation Plant	Manatee Comm	31100	4.9%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	14.1%	174,543.23	174,543.23
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31200	4.0%	127,429.19	127,429.19
	02 - Steam Generation Plant	Martin Comm	31100	1.7%	1,110,450.32	1,110,450.32
	02 - Steam Generation Plant	Martin U1	31100	1.5%	176,338.83	176,338.83
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	1,132,078.22	1,132,078.22
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	1,081,354.77	1,081,354.77
	02 - Steam Generation Plant	Sanford U3	31100	4.0%	796,754.11	796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.1%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.0%	2,292.39	2,292.39
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.3%	87,560.23	87,560.23
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.1%	42,158.96	42,158.96
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.4%	898,110.65	898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.5%	584,290.23	584,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	5.0%	68,893.65	68,893.65
	05 - Other Generation Plant	PtEverglades GTs	34200	5.1%	2,359,099.94	2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	3.7%	749,025.94	749,025.94
	Total For Project 05 - Maintenance of Above Ground Fuel Tanks				13,550,217.48	13,550,217.48
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	StLucie U1	32300	1.2%	31,030.00	31,030.00
	Total For Project 07 - Relocate Turbine Lube Oil Piping				31,030.00	31,030.00
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Amortizable	31670	7-Yr	273,695.22	283,913.98
	02 - Steam Generation Plant	CapeCanaveral Comm	31600	2.8%	0.00	25,000.00
	02 - Steam Generation Plant	Martin Comm	31600	3.2%	23,107.32	23,107.32
	05 - Other Generation Plant	Amortizable	34670	7-Yr	45,699.54	45,699.54
	08 - General Plant	Amortizable	39130	7-Yr	0.00	35,000.00
	Total For Project 08 - Oil Spill Clean-up/Response Equipment				342,502.08	412,720.84
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.4%	117,793.83	117,793.83
	Total For Project 10 - Reroute Storm Water Runoff				117,793.83	117,793.83
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31000	0.0%	9,936.72	9,936.72
	02 - Steam Generation Plant	Scherer Comm	31100	1.6%	524,872.97	524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	1.6%	328,761.62	328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	1.0%	689.11	689.11
	Total For Project 12 - Scherer Discharge Pipline				864,260.42	864,260.42
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	706,500.94	706,500.94
	02 - Steam Generation Plant	Martin U1	31200	1.8%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	1.5%	416,671.92	416,671.92
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	296,707.34	296,707.34
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	560,786.81	560,786.81
	Total For Project 20 - Wastewater/Stormwater Discharge Elimination				2,361,661.78	2,361,661.78
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.4%	828,789.34	828,789.34
	Total For Project 21 - St. Lucie Turtle Nets				828,789.34	828,789.34

Florida Power & Light Company
Environmental Cost Recovery Clause
2007 Annual Capital Depreciation Schedule

Project Number	Function	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Actual 12/31/2006 Plant In Service	Estimated 12/31/2007 Plant In Service
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	665,907.33	665,907.33
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.7%	13,451.85	13,451.85
	02 - Steam Generation Plant	CapeCanaveral Comm	31500	1.9%	13,450.30	13,450.30
	02 - Steam Generation Plant	Cutler Comm	31400	0.0%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	0.2%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	4.9%	95,458.00	336,763.43
	02 - Steam Generation Plant	Manatee Comm	31500	3.7%	5,000.00	5,000.00
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	10,379.00	10,379.00
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	205,014.03	205,014.03
	02 - Steam Generation Plant	Riviera U3	31200	1.7%	736,958.97	736,958.97
	02 - Steam Generation Plant	Riviera U4	31200	1.4%	894,298.77	894,298.77
	02 - Steam Generation Plant	Sanford U3	31100	4.0%	213,687.21	213,687.21
	02 - Steam Generation Plant	Sanford U3	31200	3.6%	211,727.22	211,727.22
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31500	2.1%	13,559.00	13,559.00
	03 - Nuclear Generation Plant	StLucie U1	32400	1.7%	0.00	437,209.61
	03 - Nuclear Generation Plant	StLucie U2	32300	1.9%	0.00	396,084.37
	05 - Other Generation Plant	Amortizable	34670	7-Yr	7,065.10	7,065.10
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.1%	189,219.17	189,219.17
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.4%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	FtLauderdale Comm	34300	1.8%	28,250.00	28,250.00
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.2%	92,726.74	92,726.74
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.5%	513,250.07	513,250.07
	05 - Other Generation Plant	FtMyers GTs	34100	2.1%	98,714.92	98,714.92
	05 - Other Generation Plant	FtMyers GTs	34200	5.0%	629,983.29	629,983.29
	05 - Other Generation Plant	FtMyers GTs	34500	2.9%	12,430.00	12,430.00
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.5%	49,727.00	49,727.00
	05 - Other Generation Plant	FtMyers U3 CC	34500	4.8%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.4%	61,215.95	61,215.95
	05 - Other Generation Plant	PtEverglades GTs	34100	1.5%	454,080.68	454,080.68
	05 - Other Generation Plant	PtEverglades GTs	34200	5.1%	1,703,610.61	1,703,610.61
	05 - Other Generation Plant	Putnam Comm	34100	4.1%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	3.7%	1,713,191.94	1,713,191.94
	05 - Other Generation Plant	Putnam Comm	34500	4.2%	60,746.93	60,746.93
	06 - Transmission Plant - Electric		35200	2.5%	951,562.91	951,562.91
	06 - Transmission Plant - Electric		35300	2.8%	177,981.88	177,981.88
	07 - Distribution Plant - Electric		36100	2.6%	2,862,088.65	2,862,093.44
	08 - General Plant		39000	2.7%	7,975.00	7,975.00
		Total For Project 23 - Spill Prevention Clean-Up & Countermeasures			14,364,447.18	15,439,051.38
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	15,479,973.76	17,690,083.30
	02 - Steam Generation Plant	Manatee U2	31200	4.0%	14,743,192.81	16,847,955.46
		Total For Project 24 - Manatee Reburn			30,223,166.57	34,538,038.76
25 - PPE ESP Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.7%	13,082,737.27	13,091,907.19
	02 - Steam Generation Plant	PtEverglades U1	31500	2.0%	418,393.78	418,687.04
	02 - Steam Generation Plant	PtEverglades U2	31200	6.1%	15,794,922.02	15,804,017.73
	02 - Steam Generation Plant	PtEverglades U2	31500	2.1%	638,102.67	638,470.14
	02 - Steam Generation Plant	PtEverglades U3	31100	2.6%	0.00	4,812,793.71
	02 - Steam Generation Plant	PtEverglades U3	31200	4.0%	0.00	16,125,920.25
	02 - Steam Generation Plant	PtEverglades U3	31500	2.2%	0.00	2,531,026.34
	02 - Steam Generation Plant	PtEverglades U4	31200	3.6%	0.00	25,326,653.05
	02 - Steam Generation Plant	PtEverglades U4	31500	2.1%	0.00	3,091,243.18
		Total For Project 25 - PPE ESP Technology			29,934,155.74	81,840,718.63
31 - Clean Air Interstate Rule (CAIR)						
	05 - Other Generation Plant	FtLauderdale GTs	34300	2.2%	0.00	132,333.00
	05 - Other Generation Plant	FtMyers GTs	34300	3.1%	0.00	132,333.00
	05 - Other Generation Plant	PtEverglades GTs	34300	2.6%	0.00	132,333.00
		Total For Project 31 - Clean Air Interstate Rule (CAIR)			0.00	396,999.00
		Total For All Projects			122,799,944.57	180,635,325.32

APPENDIX I

ENVIRONMENTAL COST RECOVERY

COMMISSION FORMS 42-1P THROUGH 42-7P
JANUARY 2008 – DECEMBER 2008

REVISED FORMS 42-1E, 42-2E, 42-3E, 42-6E, 42-7E, 42-8E, PAGES 39-40
JANUARY 2007 – DECEMBER 2007

KMD-3
DOCKET NO. 070007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT _____
PAGES 1-104

1 FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 60
COMPANY Florida Power & Light
WITNESS K. M. Dubin (KMD-3)
DATE 11-06-07

Form 42-1P

Florida Power & Light Company

Environmental Cost Recovery Clause

Total Jurisdictional Amount to Be Recovered

For the Projected Period

January 2008 to December 2008

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)	7,614,080	3,866,972	687,584	12,168,636
	b Projected Capital Projects (FORM 42-3P, Page 2 of 2, Lines 7 through 9)	19,419,122	13,124,403	0	32,543,525
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	27,033,202	16,991,375	687,584	44,712,161
2	True-up for Estimated Over/(Under) Recovery for the current period January 2007 - December 2007 (FORM 42-1E, Line 4, revised on August 31, 2007)	(314,178)	(259,345)	(12,302)	(585,826)
3	Final True-up Over/(Under) for the period January 2006 - December 2006 (FORM 42-1A, Line 7, filed on April 2, 2007)	730,005	795,374	38,471	1,563,849
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2008 - December 2008 (Line 1 - Line 2 - Line 3)	26,617,376	16,455,347	661,416	43,734,138
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier 1.00072)	26,636,540	16,467,194	661,892	43,765,627

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 2008 - December 2008

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	$163,772	$163,772	$163,772	$163,772	$163,772	$163,772	$982,632
	3a Continuous Emission Monitoring Systems-O&M	174,186	38,841	38,841	38,841	38,841	189,186	518,736
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	37,500	115,000	477,500	17,500	23,072	0	670,572
	8a Oil Spill Cleanup/Response Equipment-O&M	15,150	15,150	40,150	15,150	25,150	40,150	150,900
	13 RCRA Corrective Action-O&M	0	2,000	0	20,000	0	0	22,000
	14 NPDES Permit Fees-O&M	124,900	0	7,500	0	0	7,500	139,900
	17a Disposal of Noncontainerized Liquid Waste-O&M	20,000	28,000	35,000	30,000	10,000	28,000	151,000
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	146,700	191,650	175,750	36,900	66,850	54,850	672,700
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	34,450	28,450	40,450	80,900	0	0	184,250
	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	(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(538,824)
	21 St. Lucie Turtle Net	10,000	0	0	0	0	0	10,000
	22 Pipeline Integrity Management	0	0	0	100,000	160,000	0	260,000
	23 SPCC - Spill Prevention, Control & Countermeasures	6,000	6,000	6,000	16,000	16,000	81,000	131,000
	24 Manatee Reburn	30,000	15,000	80,000	40,000	15,000	20,000	200,000
	25 Pt. Everglades ESP Technology	196,032	196,032	196,032	196,032	196,032	196,032	1,176,192
	26 UST Replacement/Removal	0	0	0	0	0	0	0
	27 Lowest Quality Water Source	25,075	25,075	25,075	25,075	25,075	25,075	150,450
	28 CWA 316(b) Phase II Rule	119,478	119,478	119,478	119,478	119,478	119,478	716,868
	29 SCR Consumables	18,600	138,600	66,600	66,600	66,600	86,600	443,600
	30 HBMP	1,700	11,700	1,700	1,700	1,700	1,700	20,200
	31 CAIR Compliance	7,917	7,917	257,917	257,917	107,917	7,917	647,502
	32 BART	0	0	0	0	0	0	0
	34 St. Lucie Cooling Water System Inspection & Maintenance	442,000	0	0	0	0	0	442,000
	35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
2	Total of O&M Activities	$1,436,970	$ 966,175	$ 1,595,275	$ 1,089,375	$ 898,997	$ 884,770	$ 6,871,562
3	Recoverable Costs Allocated to Energy	$ 536,707	$ 513,901	$ 789,824	$ 722,935	$ 531,712	$ 640,057	$ 3,735,137
4a	Recoverable Costs Allocated to CP Demand	$ 776,906	$ 283,967	$ 653,044	$ 352,883	$ 323,778	$ 213,206	$ 2,603,783
4b	Recoverable Costs Allocated to GCP Demand	$ 123,357	$ 168,307	$ 152,407	$ 13,557	$ 43,507	$ 31,507	$ 532,642
5	Retail Energy Jurisdictional Factor	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	
6a	Retail CP Demand Jurisdictional Factor	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$ 529,093	$ 506,610	$ 778,618	$ 712,679	$ 524,169	$ 630,976	$ 3,682,145
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 767,276	$ 280,447	$ 644,949	$ 348,508	$ 319,764	$ 210,563	$ 2,571,507
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 123,357	$ 168,307	$ 152,407	$ 13,557	$ 43,507	$ 31,507	$ 532,642
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,419,726	$ 955,364	$ 1,575,974	$ 1,074,744	$ 887,440	$ 873,046	$ 6,786,294

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 2008 - December 2008

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	$163,772	$163,772	$163,772	$163,772	$163,772	$163,772	$982,632	$1,965,264			$1,965,264
	3a Continuous Emission Monitoring Systems-O&M	38,841	38,841	38,841	38,841	38,841	38,841	233,046	751,782			751,782
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	0	6,500	0	0	0	0	6,500	677,072	677,072		
	8a Oil Spill Cleanup/Response Equipment-O&M	15,150	25,150	40,150	15,150	15,150	15,150	125,900	276,800			276,800
	13 RCRA Corrective Action-O&M	0	0	0	0	0	100,000	100,000	122,000	122,000		
	14 NPDES Permit Fees-O&M	0	7,500	0	0	7,500	0	15,000	154,900	154,900		
	17a Disposal of Noncontainerized Liquid Waste-O&M	52,000	15,000	31,000	17,000	20,000	13,000	148,000	299,000			299,000
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	24,900	7,900	30,850	88,800	65,800	76,750	295,000	967,700		967,700	
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	0	0	0	74,900	97,350	0	172,250	356,500	329,077		27,423
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)	(560,232)	(258,569)	(280,116)	(21,547)
	20 Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0	0	0		
	NA Amortization of Gains on Sales of Emissions Allowances	(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(538,824)	(1,077,648)			(1,077,648)
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0	10,000	10,000		
	22 Pipeline Integrity Management	0	0	0	0	0	0	0	260,000	260,000		
	23 SPCC - Spill Prevention, Control & Countermeasures	70,000	58,000	58,000	58,000	6,000	6,000	256,000	387,000	387,000		
	24 Manatee Rebum	20,000	20,000	70,000	70,000	70,000	50,000	300,000	500,000			500,000
	25 Pt. Everglades ESP Technology	196,032	196,032	196,032	196,032	196,032	196,032	1,176,192	2,352,384			2,352,384
	26 UST Replacement/Removal	0	0	0	0	0	0	0	0	0		
	27 Lowest Quality Water Source	25,075	25,075	25,075	25,075	25,075	25,075	150,450	300,900	300,900		
	28 CWA 316(b) Phase II Rule	119,474	119,478	119,478	119,478	119,478	119,474	716,860	1,433,728	1,433,728		
	29 SCR Consumables	66,600	82,600	66,600	66,600	66,600	62,600	411,600	855,200			855,200
	30 HBMP	1,700	6,700	1,700	6,700	1,700	1,700	20,200	40,400	40,400		
	31 CAIR Compliance	7,917	7,917	7,917	367,917	367,917	387,917	1,147,502	1,795,004			1,795,004
	32 BART	0	0	0	0	0	0	0	0			0
	34 St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0	0	0	0	442,000	442,000		
	35 Martin Plant Drinking Water System Compliance	0	10,000	7,000	0	0	0	17,000	17,000	17,000		
2	Total of O&M Activities	$ 664,971	$ 653,975	$ 719,925	$1,171,775	$1,124,725	$1,119,821	$ 5,455,192	$12,326,754	$ 3,915,508	$ 687,584	$7,723,662
3	Recoverable Costs Allocated to Energy	$ 468,712	$ 457,712	$ 522,712	$ 849,474	$ 854,201	$ 835,712	$ 3,988,524	$ 7,723,662			
4a	Recoverable Costs Allocated to CP Demand	$ 194,702	$ 211,706	$ 189,706	$ 256,844	$ 228,067	$ 230,702	$ 1,311,726	$ 3,915,508			
4b	Recoverable Costs Allocated to GCP Demand	$ 1,557	$ (15,443)	$ 7,507	$ 65,457	$ 42,457	$ 53,407	$ 154,942	$ 687,584			
5	Retail Energy Jurisdictional Factor	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%					
6a	Retail CP Demand Jurisdictional Factor	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	$ 462,062	$ 451,218	$ 515,296	$ 837,422	$ 842,082	$ 823,855	$ 3,931,935	$ 7,614,080			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 192,288	$ 209,081	$ 187,354	$ 253,660	$ 225,240	$ 227,842	$ 1,295,465	$ 3,866,972			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 1,557	$ (15,443)	$ 7,507	$ 65,457	$ 42,457	$ 53,407	$ 154,942	$ 687,584			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 655,907	$ 644,856	$ 710,157	$1,156,539	$1,109,779	$1,105,104	$ 5,382,342	$12,168,636			

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 2008 - December 2008

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	$ 72,973	$ 72,559	$ 72,144	$ 71,730	$ 71,315	$ 70,901	$ 431,622
3b	Continuous Emission Monitoring Systems-Capital	85,105	85,357	85,654	85,792	85,687	85,582	513,177
4b	Clean Closure Equivalency-Capital	326	325	324	323	322	321	1,941
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	143,912	143,504	143,097	142,690	142,282	141,875	857,360
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	131	131	131	131	130	130	784
8b	Oil Spill Cleanup/Response Equipment-Capital	6,794	6,753	6,990	7,226	7,184	7,143	42,090
10	Relocate Storm Water Runoff-Capital	804	802	801	800	799	797	4,803
NA	SO2 Allowances-Negative Return on Investment	(21,649)	(20,818)	(19,988)	(19,157)	(18,327)	(17,496)	(117,435)
12	Scherer Discharge Pipeline-Capital	5,291	5,280	5,270	5,259	5,249	5,238	31,587
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	20,266	20,232	20,199	20,165	20,131	20,097	121,090
21	St. Lucie Turtle Net	7,647	7,638	9,128	10,616	10,604	10,592	56,225
22	Pipeline Integrity Management	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	169,688	169,305	168,922	168,775	169,133	169,254	1,015,077
24	Manatee Reburn	425,160	423,986	422,812	421,639	420,465	419,291	2,533,353
25	Pt. Everglades ESP Technology	1,007,476	1,004,651	1,001,826	999,001	996,176	993,351	6,002,481
26	UST Removal / Replacement	0	0	0	0	0	0	0
31	CAIR Compliance	283,856	309,908	350,131	390,838	417,855	444,861	2,197,449
33	CAMR Compliance	104,732	147,724	190,717	233,710	276,703	319,696	1,273,282
35	Martin Plant Drinking Water System Compliance	0	0	767	1,534	1,532	1,530	5,363
36	Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	2,312,512	2,377,337	2,458,925	2,541,072	2,607,240	2,673,163	14,970,249
3	Recoverable Costs Allocated to Energy	$ 1,626,253	$ 1,628,166	$ 1,631,408	$ 1,634,549	$ 1,636,233	$ 1,637,901	$ 9,794,510
4	Recoverable Costs Allocated to Demand	$ 686,259	$ 749,171	$ 827,517	$ 906,523	$ 971,007	$ 1,035,262	$ 5,175,739
5	Retail Energy Jurisdictional Factor	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	
6	Retail Demand Jurisdictional Factor	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,603,180	$ 1,605,066	$ 1,608,262	$ 1,611,358	$ 1,613,019	$ 1,614,663	$ 9,655,548
8	Jurisdictional Demand Recoverable Costs (C)	$ 677,752	$ 739,885	$ 817,260	$ 895,287	$ 958,971	$ 1,022,430	$ 5,111,585
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 2,280,932	$ 2,344,951	$ 2,425,522	$ 2,506,645	$ 2,571,990	$ 2,637,093	$ 14,767,133

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 2008 - December 2008

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	$ 70,487	$ 70,072	$ 69,658	$ 69,243	$ 68,829	$ 68,414	$ 416,703	$848,325		$ 848,325
3b	Continuous Emission Monitoring Systems-Capital	85,254	84,926	84,645	84,364	84,036	83,707	506,932	$1,020,109		1,020,109
4b	Clean Closure Equivalency-Capital	319	318	317	316	315	314	1,899	$3,840	3,545	295
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	141,468	141,060	140,653	140,246	139,838	139,431	842,696	$1,700,056	1,569,282	130,774
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	130	129	129	129	129	128	774	$1,558	1,438	120
8b	Oil Spill Cleanup/Response Equipment-Capital	7,102	7,060	7,019	6,978	6,937	7,311	42,407	$84,497	77,997	6,500
10	Relocate Storm Water Runoff-Capital	796	795	793	792	791	790	4,757	$9,560	8,825	735
NA	SO2 Allowances-Negative Return on Investment	(16,666)	(15,835)	(15,005)	(14,174)	(13,344)	(12,513)	(87,537)	($204,972)		(204,972)
12	Scherer Discharge Pipeline-Capital	5,228	5,217	5,207	5,196	5,186	5,175	31,209	$62,796	57,966	4,830
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0	$0	0	0
20	Wastewater Discharge Elimination &Reuse	20,064	20,030	19,996	19,962	19,929	19,895	119,876	$240,966	222,430	18,536
21	St. Lucie Turtle Net	10,580	10,568	10,556	10,544	10,532	10,520	63,300	$119,525	110,331	9,194
22	Pipeline Integrity Management	0	0	1,387	2,774	2,774	7,782	14,717	$14,717	13,585	1,132
23	SPCC - Spill Prevention, Control & Countermeasures	171,528	180,723	187,756	188,041	188,243	213,354	1,129,645	$2,144,722	1,979,743	164,979
24	Manatee Reburn	418,117	416,944	415,770	414,596	413,422	412,248	2,491,097	$5,024,450		5,024,450
25	Pt. Everglades ESP Technology	990,526	987,701	984,876	982,051	979,226	976,402	5,900,782	$11,903,263		11,903,263
26	UST Removal / Replacement	0	0	0	0	0	0	0	$0	0	0
31	CAIR Compliance	471,855	498,837	525,808	603,116	730,761	877,680	3,708,057	$5,905,506	5,451,236	454,270
33	CAMR Compliance	362,688	405,681	448,674	491,667	534,660	577,652	2,821,022	$4,094,304	3,779,358	314,946
35	Martin Plant Drinking Water System Compliance	1,528	1,526	1,524	1,523	1,521	1,519	9,141	$14,504	13,388	1,116
36	Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0	$0	0	0
2	Total Investment Projects - Recoverable Costs	2,741,004	2,815,752	2,889,763	3,007,364	3,173,785	3,389,809	18,017,477	32,987,726	13,289,124	19,698,602
3	Recoverable Costs Allocated to Energy	$ 1,639,509	$ 1,641,650	$ 1,643,776	$ 1,649,256	$ 1,658,447	$ 1,671,454	$ 9,904,092	$ 19,698,602		
4	Recoverable Costs Allocated to Demand	$ 1,101,495	$ 1,174,102	$ 1,245,987	$ 1,358,108	$ 1,515,338	$ 1,718,355	$ 8,113,385	$ 13,289,124		
5	Retail Energy Jurisdictional Factor	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%				
6	Retail Demand Jurisdictional Factor	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%				
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,616,248	$ 1,618,358	$ 1,620,455	$ 1,625,856	$ 1,634,917	$ 1,647,740	$ 9,763,574	$ 19,419,122		
8	Jurisdictional Demand Recoverable Costs (C)	$ 1,087,842	$ 1,159,549	$ 1,230,543	$ 1,341,274	$ 1,496,555	$ 1,697,055	$ 8,012,818	$ 13,124,403		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 2,704,090	$ 2,777,907	$ 2,850,998	$ 2,967,130	$ 3,131,472	$ 3,344,795	$ 17,776,392	$ 32,543,525		

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 2008

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								$0
	b. Clearings to Plant								$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	n/a
3.	Less: Accumulated Depreciation (C)	14,406,061	14,450,875	14,495,688	14,540,502	14,585,315	14,630,129	14,674,942	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$3,067,332	$3,022,518	$2,977,705	$2,932,891	$2,888,078	$2,843,265	$2,798,451	n/a
6.	Average Net Investment		3,044,925	3,000,112	2,955,298	2,910,485	2,865,671	2,820,858	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		23,398	23,053	22,709	22,365	22,020	21,676	135,221
	b. Debt Component (Line 6 x 1.8767% x 1/12)		4,762	4,692	4,622	4,552	4,482	4,412	27,521
8.	Investment Expenses								
	a. Depreciation (E)		44,813	44,813	44,813	44,813	44,813	44,813	268,881
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$72,973	$72,559	$72,144	$71,730	$71,315	$70,901	$431,622

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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								$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	n/a
3.	Less: Accumulated Depreciation (C)	14,674,942	14,719,756	14,764,569	14,809,383	14,854,196	14,899,010	14,943,823	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$2,798,451	$2,753,638	$2,708,824	$2,664,011	$2,619,197	$2,574,384	$2,529,570	n/a
6.	Average Net Investment		2,776,044	2,731,231	2,686,417	2,641,604	2,596,790	2,551,977	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		21,332	20,987	20,643	20,299	19,954	19,610	258,045
	b. Debt Component (Line 6 x 1.8767% x 1/12)		4,342	4,271	4,201	4,131	4,061	3,991	52,519
8.	Investment Expenses								
	a. Depreciation (E)		44,813	44,813	44,813	44,813	44,813	44,813	537,762
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$70,487	$70,072	$69,658	$69,243	$68,829	$68,414	$848,325

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		79,000	30,000	67,500	0	42,000		$218,500
	c. Retirements								$0
	d. Other (A)								$0
2.	Plant-In-Service/Depreciation Base (B)	$12,721,785	12,800,785	12,830,785	12,898,285	12,898,285	12,940,285	12,940,285	0
3.	Less: Accumulated Depreciation (C)	7,329,194	7,364,225	7,399,328	7,434,603	7,470,030	7,505,486	7,540,971	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$5,392,591	$5,436,560	$5,431,457	$5,463,683	$5,428,255	$5,434,799	$5,399,314	n/a
6.	Average Net Investment		5,414,575	5,434,009	5,447,570	5,445,969	5,431,527	5,417,056	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		41,607	41,756	41,860	41,848	41,737	41,626	250,432
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,468	8,498	8,520	8,517	8,494	8,472	50,969
8.	Investment Expenses								
	a. Depreciation (E)		35,031	35,102	35,275	35,427	35,456	35,485	211,777
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$85,105	$85,357	$85,654	$85,792	$85,687	$85,582	$513,178

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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				$7,500				$226,000
	b. Clearings to Plant								$0
	c. Retirements								$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$12,940,285	12,940,285	12,940,285	12,947,785	12,947,785	12,947,785	12,947,785	n/a
3.	Less: Accumulated Depreciation (C)	7,540,971	7,576,456	7,611,941	7,647,439	7,682,949	7,718,459	7,753,969	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$5,399,314	$5,363,829	$5,328,344	$5,300,346	$5,264,836	$5,229,326	$5,193,816	n/a
6.	Average Net Investment		5,381,571	5,346,086	5,314,345	5,282,591	5,247,081	5,211,571	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		41,353	41,080	40,836	40,592	40,319	40,047	494,660
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,416	8,361	8,311	8,262	8,206	8,150	100,675
8.	Investment Expenses								
	a. Depreciation (E)		35,485	35,485	35,498	35,510	35,510	35,510	424,775
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$85,254	$84,926	$84,645	$84,364	$84,036	$83,707	$1,020,110

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	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)	35,581	35,692	35,803	35,914	36,024	36,135	36,246	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$23,285	$23,174	$23,063	$22,952	$22,842	$22,731	$22,620	n/a
6.	Average Net Investment		23,229	23,119	23,008	22,897	22,786	22,675	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		178	178	177	176	175	174	1,058
	b. Debt Component (Line 6 x 1.8767% x 1/12)		36	36	36	36	36	35	215
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$326	$325	$324	$323	$322	$321	$1,941

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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)	36,246	36,357	36,468	36,578	36,689	36,800	36,911	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$22,620	$22,509	$22,398	$22,288	$22,177	$22,066	$21,955	n/a
6.	Average Net Investment		22,565	22,454	22,343	22,232	22,121	22,011	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		173	173	172	171	170	169	2,086
	b. Debt Component (Line 6 x 1.8767% x 1/12)		35	35	35	35	35	34	425
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	1,330
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$319	$318	$317	$316	$315	$314	$3,840

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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 Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	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)	$13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	n/a
3.	Less: Accumulated Depreciation (C)	2,729,709	2,773,755	2,817,802	2,861,848	2,905,894	2,949,941	2,993,987	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$10,820,509	$10,776,463	$10,732,416	$10,688,370	$10,644,323	$10,600,277	$10,556,230	n/a
6.	Average Net Investment		10,798,486	10,754,439	10,710,393	10,666,347	10,622,300	10,578,254	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		82,977	82,639	82,300	81,962	81,624	81,285	492,787
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16,888	16,819	16,750	16,681	16,612	16,544	100,294
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,046	44,046	44,046	44,046	44,046	264,279
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$143,912	$143,504	$143,097	$142,690	$142,282	$141,875	$857,360

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	n/a
3.	Less: Accumulated Depreciation (C)	2,993,987	3,038,034	3,082,080	3,126,127	3,170,173	3,214,220	3,258,266	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$10,556,230	$10,512,184	$10,468,137	$10,424,091	$10,380,044	$10,335,998	$10,291,952	n/a
6.	Average Net Investment		10,534,207	10,490,161	10,446,114	10,402,068	10,358,021	10,313,975	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		80,947	80,608	80,270	79,931	79,593	79,254	973,390
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16,475	16,406	16,337	16,268	16,199	16,130	198,109
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,046	44,046	44,046	44,046	44,046	528,558
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$141,468	$141,060	$140,653	$140,246	$139,838	$139,431	$1,700,056

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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 Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant							$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)	20,154	20,185	20,216	20,248	20,279	20,310	20,341	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$10,876	$10,845	$10,814	$10,783	$10,751	$10,720	$10,689	n/a
6.	Average Net Investment		10,860	10,829	10,798	10,767	10,736	10,705	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		83	83	83	83	82	82	497
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17	17	17	17	17	17	101
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	186
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$131	$131	$131	$131	$130	$130	$784

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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)	20,341	20,372	20,403	20,434	20,465	20,496	20,527	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$10,689	$10,658	$10,627	$10,596	$10,565	$10,534	$10,503	n/a
6.	Average Net Investment		10,674	10,643	10,612	10,581	10,550	10,519	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		82	82	82	81	81	81	986
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17	17	17	17	16	16	201
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	372
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$130	$129	$129	$129	$129	$128	$1,558

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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 Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant				55,000				$55,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$412,721	412,721	412,721	467,721	467,721	467,721	467,721	n/a
3.	Less: Accumulated Depreciation (C)	153,608	158,026	162,444	166,885	171,349	175,813	180,277	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$259,113	$254,695	$250,277	$300,836	$296,372	$291,908	$287,444	n/a
6.	Average Net Investment		256,904	252,486	275,556	298,604	294,140	289,676	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,974	1,940	2,117	2,295	2,260	2,226	12,812
	b. Debt Component (Line 6 x 1.8767% x 1/12)		402	395	431	467	460	453	2,608
8.	Investment Expenses								
	a. Depreciation (E)		4,418	4,418	4,441	4,464	4,464	4,464	26,670
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$6,794	$6,753	$6,990	$7,226	$7,184	$7,143	$42,090

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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							$67,000	$122,000
	b. Clearings to Plant								
	c. Retirements								
	d. Other (A)								
2.	Plant-in-Service/Depreciation Base (B)	$467,721	467,721	467,721	467,721	467,721	467,721	534,721	n/a
3.	Less: Accumulated Depreciation (C)	180,277	184,742	189,206	193,670	198,134	202,598	207,169	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$287,444	$282,980	$278,516	$274,051	$269,587	$265,123	$327,553	n/a
6.	Average Net Investment		285,212	280,748	276,283	271,819	267,355	296,338	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,192	2,157	2,123	2,089	2,054	2,277	25,704
	b. Debt Component (Line 6 x 1.8767% x 1/12)		446	439	432	425	418	463	5,231
8.	Investment Expenses								
	a. Depreciation (E)		4,464	4,464	4,464	4,464	4,464	4,571	53,561
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,102	$7,060	$7,019	$6,978	$6,937	$7,311	$84,497

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant							$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)	45,686	45,823	45,960	46,098	46,235	46,373	46,510	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$72,108	$71,971	$71,834	$71,696	$71,559	$71,421	$71,284	n/a
6.	Average Net Investment		72,040	71,902	71,765	71,627	71,490	71,353	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		554	553	551	550	549	548	3,306
	b. Debt Component (Line 6 x 1.8767% x 1/12)		113	112	112	112	112	112	673
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	825
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$804	$802	$801	$800	$799	$797	$4,803

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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)	46,510	46,648	46,785	46,922	47,060	47,197	47,335	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$71,284	$71,146	$71,009	$70,872	$70,734	$70,597	$70,459	n/a
6.	Average Net Investment		71,215	71,078	70,940	70,803	70,665	70,528	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		547	546	545	544	543	542	6,573
	b. Debt Component (Line 6 x 1.8767% x 1/12)		111	111	111	111	111	110	1,338
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	1,649
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$796	$795	$793	$792	$791	$790	$9,560

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant							$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)	414,708	415,846	416,985	418,124	419,263	420,401	421,540	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$449,552	$448,414	$447,275	$446,136	$444,997	$443,859	$442,720	n/a
6.	Average Net Investment		448,983	447,844	446,705	445,567	444,428	443,289	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,450	3,441	3,433	3,424	3,415	3,406	20,569
	b. Debt Component (Line 6 x 1.8767% x 1/12)		702	700	699	697	695	693	4,186
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	6,833
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,291	$5,280	$5,270	$5,259	$5,249	$5,238	$31,587

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 42-4P, pages 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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)	421,540	422,679	423,818	424,956	426,095	427,234	428,373	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$442,720	$441,581	$440,442	$439,304	$438,165	$437,026	$435,887	n/a
6.	Average Net Investment		442,150	441,012	439,873	438,734	437,595	436,457	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,398	3,389	3,380	3,371	3,363	3,354	40,823
	b. Debt Component (Line 6 x 1.8767% x 1/12)		691	690	688	686	684	683	8,309
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	13,665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,228	$5,217	$5,207	$5,196	$5,186	$5,175	$62,796

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant							$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant							$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	562,995	566,644	570,293	573,941	577,590	581,239	584,888	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,798,666	$1,795,018	$1,791,369	$1,787,720	$1,784,071	$1,780,423	$1,776,774	n/a
6.	Average Net Investment		1,796,842	1,793,193	1,789,545	1,785,896	1,782,247	1,778,598	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		13,807	13,779	13,751	13,723	13,695	13,667	82,423
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,810	2,804	2,799	2,793	2,787	2,782	16,775
8.	Investment Expenses								
	a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	21,892
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$20,266	$20,232	$20,199	$20,165	$20,131	$20,097	$121,090

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	$584,888	588,536	592,185	595,834	599,482	603,131	606,780	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,776,774	$1,773,125	$1,769,477	$1,765,828	$1,762,179	$1,758,531	$1,754,882	n/a
6.	Average Net Investment		1,774,950	1,771,301	1,767,652	1,764,004	1,760,355	1,756,706	
7.	Return on Average Net Investment								
	Equity Component grossed up for taxes (D)		13,639	13,611	13,583	13,555	13,527	13,499	163,836
	Debt Component (Line 6 x 1.8767% x 1/12)		2,776	2,770	2,764	2,759	2,753	2,747	33,345
8.	Investment Expenses								
	a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	43,785
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$20,064	$20,030	$19,996	$19,962	$19,929	$19,895	$240,966

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant				288,000			$0	$288,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	828,789	828,789	828,789	1,116,789	1,116,789	1,116,789	1,116,789	n/a
3.	Less: Accumulated Depreciation (C)	105,991	106,958	107,925	109,060	110,363	111,666	112,969	n/a
4.	CWIP - Non Interest Bearing		0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$722,798	$721,831	$720,864	$1,007,729	$1,006,426	$1,005,123	$1,003,820	n/a
6.	Average Net Investment		722,314	721,347	864,296	1,007,078	1,005,775	1,004,472	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		5,550	5,543	6,641	7,739	7,729	7,719	40,920
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,130	1,128	1,352	1,575	1,573	1,571	8,328
8.	Investment Expenses								
	a. Depreciation (E)		967	967	1,135	1,303	1,303	1,303	6,978
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,647	$7,638	$9,128	$10,616	$10,604	$10,592	$56,225

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 42-4P, pages 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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	$288,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$1,116,789	1,116,789	1,116,789	1,116,789	1,116,789	1,116,789	1,116,789	n/a
3.	Less: Accumulated Depreciation (C)	$112,969	114,272	115,575	116,878	118,180	119,483	120,786	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,003,820	$1,002,517	$1,001,214	$999,911	$998,609	$997,306	$996,003	n/a
6.	Average Net Investment		1,003,169	1,001,866	1,000,563	999,260	997,957	996,654	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		7,709	7,699	7,688	7,678	7,668	7,658	87,021
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,569	1,567	1,565	1,563	1,561	1,559	17,711
8.	Investment Expenses								
	a. Depreciation (E)		1,303	1,303	1,303	1,303	1,303	1,303	14,795
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$10,580	$10,568	$10,556	$10,544	$10,532	$10,520	$119,525

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant							$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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				300,000	300,000	300,000		
	b. Clearings to Plant		$0	$0	$0	$0	$0	$1,200,000	$1,200,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	1,200,000	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	850	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	300,000	300,000	300,000	0	900,000
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$300,000	$300,000	$300,000	$1,199,150	n/a
6.	Average Net Investment		0	0	150,000	300,000	300,000	749,575	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	1,153	2,305	2,305	5,760	11,523
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	235	469	469	1,172	2,345
8.	Investment Expenses								
	a. Depreciation (E)							850	850
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$1,387	$2,774	$2,774	$7,782	$14,717

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 42-4P, pages 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant					41,042	90,000		$131,042
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$15,439,052	15,439,052	15,439,052	15,439,052	15,480,094	15,570,094	15,570,094	n/a
3.	Less: Accumulated Depreciation (C)	1,548,640	1,590,060	1,631,480	1,672,900	1,714,367	1,755,969	1,797,662	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$13,890,412	$13,848,992	$13,807,571	$13,766,151	$13,765,727	$13,814,124	$13,772,431	n/a
6.	Average Net Investment		13,869,702	13,828,281	13,786,861	13,765,939	13,789,926	13,793,278	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		106,577	106,259	105,941	105,780	105,964	105,990	636,510
	b. Debt Component (Line 6 x 1.8767% x 1/12)		21,691	21,626	21,562	21,529	21,566	21,572	129,545
8.	Investment Expenses								
	a. Depreciation (E)		41,420	41,420	41,420	41,466	41,603	41,693	249,022
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$169,688	$169,305	$168,922	$168,775	$169,133	$169,254	$1,015,077

Notes:

(A) Reserve Transfer/Adj.
(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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

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		$479,568	$1,117,637	$90,111	$29,223	$74,626	$4,415,176	$6,337,383
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$15,570,094	16,049,662	17,167,299	17,257,410	17,286,633	17,361,259	21,776,435	n/a
3.	Less: Accumulated Depreciation (C)	$1,797,662	1,839,799	1,884,145	1,930,359	1,976,733	2,023,260	2,074,588	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$13,772,431	$14,209,863	$15,283,153	$15,327,051	$15,309,899	$15,337,999	$19,701,847	n/a
6.	Average Net Investment		13,991,147	14,746,508	15,305,102	15,318,475	15,323,949	17,519,923	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		107,510	113,315	117,607	117,710	117,752	134,626	1,345,030
	b. Debt Component (Line 6 x 1.8767% x 1/12)		21,881	23,062	23,936	23,957	23,965	27,400	273,747
8.	Investment Expenses								
	a. Depreciation (E)		42,137	44,346	46,213	46,375	46,526	51,329	525,948
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$171,528	$180,723	$187,756	$188,041	$188,243	$213,354	$2,144,722

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(In Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant								$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$34,538,039	34,538,039	34,538,039	34,538,039	34,538,039	34,538,039	34,538,039	n/a
3.	Less: Accumulated Depreciation (C)	2,225,764	2,352,684	2,479,604	2,606,524	2,733,444	2,860,364	2,987,285	n/a
4.	CWIP - Non Interest Bearing		0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$32,312,275	$32,185,355	$32,058,435	$31,931,515	$31,804,594	$31,677,674	$31,550,754	n/a
6.	Average Net Investment		32,248,815	32,121,895	31,994,975	31,868,055	31,741,134	31,614,214	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		247,805	246,830	245,855	244,879	243,904	242,929	1,472,203
	b. Debt Component (Line 6 x 1.8767% x 1/12)		50,434	50,236	50,037	49,839	49,640	49,442	299,629
8.	Investment Expenses								
	a. Depreciation (E)		126,920	126,920	126,920	126,920	126,920	126,920	761,521
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$425,160	$423,986	$422,812	$421,639	$420,465	$419,291	$2,533,353

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(In Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$34,538,039	34,538,039	34,538,039	34,538,039	34,538,039	34,538,039	34,538,039	n/a
3.	Less: Accumulated Depreciation (C)	$2,987,285	3,114,205	3,241,125	3,368,045	3,494,965	3,621,886	3,748,806	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$31,550,754	$31,423,834	$31,296,914	$31,169,994	$31,043,073	$30,916,153	$30,789,233	n/a
6.	Average Net Investment		31,487,294	31,360,374	31,233,454	31,106,533	30,979,613	30,852,693	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		241,954	240,978	240,003	239,028	238,053	237,077	$2,909,295
	b. Debt Component (Line 6 x 1.8767% x 1/12)		49,244	49,045	48,847	48,648	48,450	48,251	$592,113
8.	Investment Expenses								
	a. Depreciation (E)		126,920	126,920	126,920	126,920	126,920	126,920	$1,523,042
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$418,117	$416,944	$415,770	$414,596	$413,422	$412,248	$5,024,450

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(In Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								$0
	b. Clearings to Plant								$0
	c. Retirements								$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$81,840,719	81,840,719	81,840,719	81,840,719	81,840,719	81,840,719	81,840,719	n/a
3.	Less: Accumulated Depreciation (C)	5,778,624	6,084,083	6,389,542	6,695,002	7,000,461	7,305,920	7,611,380	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$76,062,095	$75,756,636	$75,451,176	$75,145,717	$74,840,258	$74,534,798	$74,229,339	n/a
6.	Average Net Investment		75,909,365	75,603,906	75,298,447	74,992,987	74,687,528	74,382,069	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		583,300	580,953	578,606	576,259	573,911	571,564	3,464,594
	b. Debt Component (Line 6 x 1.8767% x 1/12)		118,716	118,238	117,760	117,283	116,805	116,327	705,130
8.	Investment Expenses								
	a. Depreciation (E)		305,459	305,459	305,459	305,459	305,459	305,459	1,832,756
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,007,476	$1,004,651	$1,001,826	$999,001	$996,176	$993,351	$6,002,481

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$81,840,719	81,840,719	81,840,719	81,840,719	81,840,719	81,840,719	81,840,719	n/a
3.	Less: Accumulated Depreciation (C)	$7,611,380	7,916,839	8,222,298	8,527,758	8,833,217	9,138,676	9,444,136	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$74,229,339	$73,923,880	$73,618,420	$73,312,961	$73,007,502	$72,702,042	$72,396,583	n/a
6.	Average Net Investment		74,076,609	73,771,150	73,465,691	73,160,231	72,854,772	72,549,313	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		569,217	566,870	564,523	562,175	559,828	557,481	$6,844,688
	b. Debt Component (Line 6 x 1.8767% x 1/12)		115,850	115,372	114,894	114,417	113,939	113,461	$1,393,062
8.	Investment Expenses								
	a. Depreciation (E)		305,459	305,459	305,459	305,459	305,459	305,459	$3,665,512
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$990,526	$987,701	$984,876	$982,051	$979,226	$976,402	$11,903,263

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0						$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$2,817,917	$2,817,917	$2,817,917	$2,171,250	$2,171,250	$2,171,250	$14,967,501
	b. Clearings to Plant		0	0	14,855,089	646,667	646,667	$646,667	$16,795,090
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$396,999	396,999	396,999	15,252,088	15,898,755	16,545,422	17,192,089	n/a
3.	Less: Accumulated Depreciation (C)	436	1,307	2,178	17,286	47,249	78,451	110,894	n/a
4.	CWIP - Non Interest Bearing	28,794,176	31,612,093	34,430,010	22,392,838	24,564,088	26,735,338	28,906,588	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$29,190,739	$32,007,784	$34,824,830	$37,627,640	$40,415,594	$43,202,308	$45,987,783	n/a
6.	Average Net Investment		30,599,262	33,416,307	36,226,235	39,021,617	41,808,951	44,595,046	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		235,130	256,777	278,368	299,849	321,267	342,676	1,734,066
	b. Debt Component (Line 6 x 1.8767% x 1/12)		47,855	52,260	56,655	61,027	65,386	69,743	352,925
8.	Investment Expenses								
	a. Depreciation (E)		871	871	15,107	29,963	31,203	32,442	110,458
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$283,856	$309,908	$350,131	$390,838	$417,855	$444,861	$2,197,449

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(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		$2,171,250	$2,171,250	$2,171,250	$13,059,582	$13,059,582	($9,197,916)	$38,402,499
	b. Clearings to Plant		$646,667	$646,667	$646,667	$646,667	$646,667	$24,104,165	$44,132,590
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,192,089	17,838,756	18,485,423	19,132,090	19,778,757	20,425,424	44,529,589	n/a
3.	Less: Accumulated Depreciation (C)	$110,894	144,575	179,496	215,656	253,056	291,696	345,376	n/a
4.	CWIP - Non Interest Bearing	$28,906,588	31,077,838	33,249,088	35,420,338	48,479,920	61,539,502	52,341,586	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$45,987,783	$48,772,019	$51,555,015	$54,336,771	$68,005,620	$81,673,230	$96,525,799	n/a
6.	Average Net Investment		47,379,901	50,163,517	52,945,893	61,171,196	74,839,425	89,099,515	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		364,075	385,465	406,845	470,050	575,079	684,656	$4,620,235
	b. Debt Component (Line 6 x 1.8767% x 1/12)		74,098	78,452	82,803	95,667	117,043	139,344	$940,331
8.	Investment Expenses								
	a. Depreciation (E)		33,682	34,921	36,160	37,400	38,639	53,680	$344,940
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$471,855	$498,837	$525,808	$603,116	$730,761	$877,680	$5,905,506

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 42-4P, pages 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$4,648,834	$4,648,834	$4,648,834	$4,648,834	$4,648,834	$4,648,834	$27,893,004
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	9,000,261	13,649,095	18,297,929	22,946,763	27,595,597	32,244,431	36,893,265	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$9,000,261	$13,649,095	$18,297,929	$22,946,763	$27,595,597	$32,244,431	$36,893,265	n/a
6.	Average Net Investment		11,324,678	15,973,512	20,622,346	25,271,180	29,920,014	34,568,848	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		87,021	122,743	158,466	194,188	229,910	265,633	1,057,961
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17,711	24,981	32,252	39,522	46,792	54,063	215,321
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)		$104,732	$147,724	$190,717	$233,710	$276,703	$319,696	$1,273,282

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(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		$4,648,834	$4,648,834	$4,648,834	$4,648,834	$4,648,834	$4,648,834	$55,786,008
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$36,893,265	41,542,099	46,190,933	50,839,767	55,488,601	60,137,435	64,786,269	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$36,893,265	$41,542,099	$46,190,933	$50,839,767	$55,488,601	$60,137,435	$64,786,269	n/a
6.	Average Net Investment		39,217,682	43,866,516	48,515,350	53,164,184	57,813,018	62,461,852	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		301,355	337,078	372,800	408,523	444,245	479,967	$3,401,928
	b. Debt Component (Line 6 x 1.8767% x 1/12)		61,333	68,604	75,874	83,144	90,415	97,685	$692,376
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)		$362,688	$405,681	$448,674	$491,667	$534,660	$577,652	$4,094,304

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Plant Drinking Water System Compliance (Project No. 35)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								$0
	b. Clearings to Plant				$144,000				$144,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	144,000	144,000	144,000	144,000	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	102	306	510	714	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$143,898	$143,694	$143,490	$143,286	n/a
6.	Average Net Investment		0	0	71,949	143,796	143,592	143,388	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	553	1,105	1,103	1,102	3,863
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	113	225	225	224	786
8.	Investment Expenses								
	a. Depreciation (E)		0	0	102	204	204	204	714
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$767	$1,534	$1,532	$1,530	$5,363

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Plant Drinking Water System Compliance (Project No. 35)
(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								$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$144,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$144,000	144,000	144,000	144,000	144,000	144,000	144,000	n/a
3.	Less: Accumulated Depreciation (C)	$714	918	1,122	1,326	1,530	1,734	1,938	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$143,286	$143,082	$142,878	$142,674	$142,470	$142,266	$142,062	n/a
6.	Average Net Investment		143,184	142,980	142,776	142,572	142,368	142,164	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,100	1,099	1,097	1,096	1,094	1,092	$10,441
	b. Debt Component (Line 6 x 1.8767% x 1/12)		224	224	223	223	223	222	$2,125
8.	Investment Expenses								
	a. Depreciation (E)		204	204	204	204	204	204	$1,938
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,528	$1,526	$1,524	$1,523	$1,521	$1,519	$14,504

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 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Radioactive Waste Storage (Project No. 36)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								$0
	b. Clearings to Plant								$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing		0	0	0	0	0	0	n/a
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	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Radioactive Waste Storage (Project No. 36)
(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								$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 43-45.
(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 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 43-45.
(F) Applicable amortization period(s). See Form 42-4P, pages 43-45.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June 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	(2,385,801)	(2,295,997)	(2,206,193)	(2,116,389)	(2,026,585)	(1,936,781)	(1,846,977)		
2	Total Working Capital	($2,385,801)	($2,295,997)	($2,206,193)	($2,116,389)	($2,026,585)	($1,936,781)	($1,846,977)		
3	Average Net Working Capital Balance		(2,340,899)	(2,251,095)	(2,161,291)	(2,071,487)	(1,981,683)	(1,891,879)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(17,988)	(17,298)	(16,608)	(15,918)	(15,228)	(14,538)	(97,576)	
	b Debt Component (Line 6 x 1.87670% x 1/12)		(3,661)	(3,521)	(3,380)	(3,240)	(3,099)	(2,959)	(19,859)	
5	Total Return Component		($21,649)	($20,818)	($19,988)	($19,157)	($18,327)	($17,496)	($117,435)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(538,824)	
	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)		($89,804)	($89,804)	($89,804)	($89,804)	($89,804)	($89,804)	($538,824)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		($111,453)	($110,622)	($109,792)	($108,961)	($108,131)	($107,300)		
	a Recoverable Costs Allocated to Energy		(111,453)	(110,622)	(109,792)	(108,961)	(108,131)	(107,300)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%		
10	Demand Jurisdictional Factor		98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%		
11	Retail Energy-Related Recoverable Costs (B)		(109,818)	(109,000)	(108,182)	(107,363)	(106,545)	(105,727)	(646,635)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($109,818)	($109,000)	($108,182)	($107,363)	($106,545)	($105,727)	($646,635)	

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 5.6640% reflects an 11.75% 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 2008

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	(1,846,977)	(1,757,173)	(1,667,369)	(1,577,565)	(1,487,761)	(1,397,957)	(1,308,153)		
2	Total Working Capital	($1,846,977)	($1,757,173)	($1,667,369)	($1,577,565)	($1,487,761)	($1,397,957)	($1,308,153)		
3	Average Net Working Capital Balance		(1,802,075)	(1,712,271)	(1,622,467)	(1,532,663)	(1,442,859)	(1,353,055)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(13,847)	(13,157)	(12,467)	(11,777)	(11,087)	(10,397)	(170,310)	
	b Debt Component (Line 6 x 1.87670% x 1/12)		(2,818)	(2,678)	(2,537)	(2,397)	(2,257)	(2,116)	(34,662)	
5	Total Return Component		($16,666)	($15,835)	($15,005)	($14,174)	($13,344)	($12,513)	($204,972)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(1,077,648)	
	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)		($89,804)	($89,804)	($89,804)	($89,804)	($89,804)	($89,804)	($1,077,648)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		($106,470)	($105,639)	($104,809)	($103,978)	($103,148)	($102,317)		
	a Recoverable Costs Allocated to Energy		(106,470)	(105,639)	(104,809)	(103,978)	(103,148)	(102,317)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%		
10	Demand Jurisdictional Factor		98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%		
11	Retail Energy-Related Recoverable Costs (B)		(104,908)	(104,090)	(103,272)	(102,453)	(101,635)	(100,817)	(1,263,810)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($104,908)	($104,090)	($103,272)	($102,453)	($101,635)	($100,817)	($1,263,810)	

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 5.6640% reflects an 11.75% 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
2008 Annual Capital Depreciation Schedule

Project Number	Function	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Estimated 12/31/2007 Plant In Service	Estimated 12/31/2008 Plant In Service
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.7%	2,700,574.97	2,700,574.97
	02 - Steam Generation Plant	PtEverglades U2	31200	6.1%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	Riviera U3	31200	1.7%	3,815,802.70	3,815,802.70
	02 - Steam Generation Plant	Riviera U4	31200	1.4%	3,246,925.80	3,246,925.80
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.0%	2,925,027.84	2,925,027.84
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.8%	2,416,089.59	2,416,089.59
		Total For Project 02 - Low NOX Burner Technology			17,473,393.17	17,473,393.17
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	59,227.10	59,227.10
	02 - Steam Generation Plant	CapeCanaveral Comm	31200	1.3%	30,059.25	30,059.25
	02 - Steam Generation Plant	CapeCanaveral U1	31200	1.4%	494,606.87	514,606.87
	02 - Steam Generation Plant	CapeCanaveral U2	31200	1.1%	511,705.24	531,705.24
	02 - Steam Generation Plant	Cutler Comm	31100	0.0%	64,883.87	64,883.87
	02 - Steam Generation Plant	Cutler Comm	31200	0.5%	27,351.73	27,351.73
	02 - Steam Generation Plant	Cutler U5	31200	0.1%	319,722.43	319,722.43
	02 - Steam Generation Plant	Cutler U6	31200	1.0%	321,129.96	321,129.96
	02 - Steam Generation Plant	Manatee Comm	31200	14.1%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	4.1%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	472,570.03	472,570.03
	02 - Steam Generation Plant	Manatee U2	31100	4.1%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	4.0%	508,734.36	516,234.36
	02 - Steam Generation Plant	Martin Comm	31200	4.1%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	1.5%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	1.8%	521,075.17	542,075.17
	02 - Steam Generation Plant	Martin U2	31100	1.5%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	1.5%	519,484.96	540,484.96
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	127,911.34	127,911.34
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.2%	61,620.47	61,620.47
	02 - Steam Generation Plant	PtEverglades U1	31200	6.7%	453,661.22	475,161.22
	02 - Steam Generation Plant	PtEverglades U2	31200	6.1%	475,113.36	496,613.36
	02 - Steam Generation Plant	PtEverglades U3	31200	4.0%	503,968.62	525,468.62
	02 - Steam Generation Plant	PtEverglades U4	31200	3.6%	532,809.90	532,809.90
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	60,973.18	60,973.18
	02 - Steam Generation Plant	Riviera Comm	31200	0.4%	13,315.76	13,315.76
	02 - Steam Generation Plant	Riviera U3	31200	1.7%	449,392.38	463,892.38
	02 - Steam Generation Plant	Riviera U4	31200	1.4%	433,421.96	447,921.96
	02 - Steam Generation Plant	Sanford U3	31100	4.0%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	3.6%	438,831.34	438,831.34
	02 - Steam Generation Plant	Scherer U4	31200	1.9%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.1%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.0%	66,188.18	66,188.18
	02 - Steam Generation Plant	SJRPP U1	31200	2.2%	107,594.02	107,594.02
	02 - Steam Generation Plant	SJRPP U2	31200	2.3%	107,562.94	107,562.94
	02 - Steam Generation Plant	Turkey Pt Comm Fsll	31100	2.3%	59,056.19	59,056.19
	02 - Steam Generation Plant	Turkey Pt Comm Fsll	31200	2.1%	29,110.85	29,110.85
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.0%	546,534.15	568,034.15
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.8%	505,638.44	527,138.44
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.1%	58,859.79	58,859.79
	05 - Other Generation Plant	FtLauderdale Comm	34500	4.1%	34,502.21	34,502.21
	05 - Other Generation Plant	FtLauderdale U4	34300	5.0%	476,456.39	476,456.39
	05 - Other Generation Plant	FtLauderdale U5	34300	3.7%	485,313.47	485,313.47
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.5%	106,324.08	106,324.08
	05 - Other Generation Plant	FtMyers U3 CC	34300	5.6%	0.00	0.00
	05 - Other Generation Plant	Martin U3	34300	5.8%	445,927.00	445,927.00
	05 - Other Generation Plant	Martin U4	34300	5.7%	435,026.31	435,026.31
	05 - Other Generation Plant	Martin U8	34300	5.5%	25,657.00	25,657.00
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.1%	82,857.82	82,857.82
	05 - Other Generation Plant	FtLauderdale Comm	34300	6.3%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	5.2%	349,440.55	349,440.55
	05 - Other Generation Plant	Putnam U2	34300	5.4%	382,844.07	382,844.07
	05 - Other Generation Plant	Sanford U4	34300	5.6%	95,501.38	95,501.38
	05 - Other Generation Plant	Sanford U5	34300	5.7%	53,641.90	53,641.90
		Total For Project 03 - Continuous Emission Monitoring			12,721,784.91	12,947,784.91
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	17,254.20	17,254.20
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	19,812.30	19,812.30
	02 - Steam Generation Plant	Turkey Pt Comm Fsll	31100	2.3%	21,799.28	21,799.28
		Total For Project 04 - Clean Closure Equivalency Demonstration			58,865.78	58,865.78
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	901,636.88	901,636.88
	02 - Steam Generation Plant	Manatee Comm	31100	4.9%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	14.1%	174,543.23	174,543.23
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31200	4.0%	127,429.19	127,429.19

Florida Power & Light Company
Environmental Cost Recovery Clause
2008 Annual Capital Depreciation Schedule

Project Number	Function	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Estimated 12/31/2007 Plant In Service	Estimated 12/31/2008 Plant In Service
	02 - Steam Generation Plant	Martin Comm	31100	1.7%	1,110,450.32	1,110,450.32
	02 - Steam Generation Plant	Martin U1	31100	1.5%	176,338.83	176,338.83
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	1,132,078.22	1,132,078.22
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	1,081,354.77	1,081,354.77
	02 - Steam Generation Plant	Sanford U3	31100	4.0%	796,754.11	796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.1%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.0%	2,292.39	2,292.39
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.3%	87,560.23	87,560.23
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.1%	42,158.96	42,158.96
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.4%	898,110.65	898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.5%	584,290.23	584,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	5.0%	68,893.65	68,893.65
	05 - Other Generation Plant	PtEverglades GTs	34200	5.1%	2,359,099.94	2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	3.7%	749,025.94	749,025.94
		Total For Project 05 - Maintenance of Above Ground Fuel Tanks			**13,550,217.48**	**13,550,217.48**
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	StLucie U1	32300	1.2%	31,030.00	31,030.00
		Total For Project 07 - Relocate Turbine Lube Oil Piping			**31,030.00**	**31,030.00**
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Amortizable	31670	7-Yr	283,913.98	283,913.98
	02 - Steam Generation Plant	CapeCanaveral Comm	31600	2.8%	25,000.00	25,000.00
	02 - Steam Generation Plant	Martin Comm	31600	3.2%	23,107.32	23,107.32
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31600	1.0%	0.00	55,000.00
	05 - Other Generation Plant	Amortizable	34670	7-Yr	45,699.54	45,699.54
	08 - General Plant	Amortizable	39130	7-Yr	35,000.00	102,000.00
		Total For Project 08 - Oil Spill Clean-up/Response Equipment			**412,720.84**	**534,720.84**
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.4%	117,793.83	117,793.83
		Total For Project 10 - Reroute Storm Water Runoff			**117,793.83**	**117,793.83**
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31000	0.0%	9,936.72	9,936.72
	02 - Steam Generation Plant	Scherer Comm	31100	1.6%	524,872.97	524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	1.6%	328,761.62	328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	1.0%	689.11	689.11
		Total For Project 12 - Scherer Discharge Pipline			**864,260.42**	**864,260.42**
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	706,500.94	706,500.94
	02 - Steam Generation Plant	Martin U1	31200	1.8%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	1.5%	416,671.92	416,671.92
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	296,707.34	296,707.34
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	560,786.81	560,786.81
		Total For Project 20 - Wastewater/Stormwater Discharge Elimination			**2,361,661.78**	**2,361,661.78**
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.4%	828,789.34	1,116,789.34
		Total For Project 21 - St. Lucie Turtle Nets			**828,789.34**	**1,116,789.34**
22 - Pipeline Integrity						
	02 - Steam Generation Plant	Martin Comm	3110	1.7%	0.00	1,200,000.00
		Total For Project 22 - Pipeline Integrity			**0.00**	**1,200,000.00**
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	665,907.33	665,907.33
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.7%	13,451.85	13,451.85
	02 - Steam Generation Plant	CapeCanaveral Comm	31500	1.9%	13,450.30	13,450.30
	02 - Steam Generation Plant	CapeCanaveral U1	31100	2.0%	0.00	30,444.00
	02 - Steam Generation Plant	CapeCanaveral U2	31100	1.3%	0.00	30,444.00
	02 - Steam Generation Plant	Cutler Comm	31400	0.0%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	0.2%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	4.9%	336,763.43	687,439.43
	02 - Steam Generation Plant	Manatee Comm	31500	3.7%	5,000.00	5,000.00
	02 - Steam Generation Plant	Manatee U1	31100	4.1%	0.00	10,935.00
	02 - Steam Generation Plant	Manatee U2	31100	4.1%	0.00	10,935.00
	02 - Steam Generation Plant	Martin Comm	31100	1.7%	0.00	45,403.00
	02 - Steam Generation Plant	Martin U1	31100	1.5%	0.00	182,506.50
	02 - Steam Generation Plant	Martin U2	31100	1.5%	0.00	182,506.50
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	10,379.00	3,429,497.00
	02 - Steam Generation Plant	PtEverglades U3	31100	2.6%	0.00	32,500.00
	02 - Steam Generation Plant	PtEverglades U4	31100	2.6%	0.00	32,500.00
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	205,014.03	205,014.03
	02 - Steam Generation Plant	Riviera U3	31200	1.7%	736,958.97	736,958.97
	02 - Steam Generation Plant	Riviera U4	31200	1.4%	894,298.77	894,298.77

Florida Power & Light Company
Environmental Cost Recovery Clause
2008 Annual Capital Depreciation Schedule

Project Number	Function	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Estimated 12/31/2007 Plant In Service	Estimated 12/31/2008 Plant In Service
	02 - Steam Generation Plant	Sanford U3	31100	4.0%	213,687.21	886,247.21
	02 - Steam Generation Plant	Sanford U3	31200	3.6%	211,727.22	211,727.22
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31500	2.1%	13,559.00	13,559.00
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.0%	0.00	118,146.50
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.8%	0.00	118,146.50
	03 - Nuclear Generation Plant	StLucie U1	32400	1.7%	437,209.61	953,113.61
	03 - Nuclear Generation Plant	StLucie U2	32300	1.9%	396,084.37	396,084.37
	03 - Nuclear Generation Plant	StLucie U2	32400	1.6%	0.00	134,003.00
	05 - Other Generation Plant	Amortizable	34670	7-Yr	7,065.10	7,065.10
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.1%	189,219.17	189,219.17
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.4%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	FtLauderdale Comm	34300	1.8%	28,250.00	28,250.00
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.2%	92,726.74	92,726.74
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.5%	513,250.07	513,250.07
	05 - Other Generation Plant	FtMyers GTs	34100	2.1%	98,714.92	98,714.92
	05 - Other Generation Plant	FtMyers GTs	34200	5.0%	629,983.29	629,983.29
	05 - Other Generation Plant	FtMyers GTs	34500	2.9%	12,430.00	12,430.00
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.5%	49,727.00	49,727.00
	05 - Other Generation Plant	FtMyers U3 CC	34500	4.8%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.4%	61,215.95	61,215.95
	05 - Other Generation Plant	Martin U8	34300	5.5%	0.00	74,555.00
	05 - Other Generation Plant	PtEverglades GTs	34100	1.5%	454,080.68	454,080.68
	05 - Other Generation Plant	PtEverglades GTs	34200	5.1%	1,703,610.61	1,703,610.61
	05 - Other Generation Plant	Putnam Comm	34100	4.1%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	3.7%	1,713,191.94	1,713,191.94
	05 - Other Generation Plant	Putnam Comm	34500	4.2%	60,746.93	60,746.93
	06 - Transmission Plant - Electric		35200	2.5%	951,562.91	1,045,587.91
	06 - Transmission Plant - Electric		35300	2.8%	177,981.88	177,981.88
	07 - Distribution Plant - Electric		36100	2.6%	2,862,093.44	3,144,168.44
	08 - General Plant		39000	2.7%	7,975.00	7,975.00
		Total For Project 23 - Spill Prevention Clean-Up & Countermeasures			15,439,051.38	21,776,434.38
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	17,690,083.30	17,690,083.30
	02 - Steam Generation Plant	Manatee U2	31200	4.0%	16,847,955.46	16,847,955.46
		Total For Project 24 - Manatee Reburn			34,538,038.76	34,538,038.76
25 - PPE ESP Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.7%	13,091,907.19	13,091,907.19
	02 - Steam Generation Plant	PtEverglades U1	31500	2.0%	418,687.04	418,687.04
	02 - Steam Generation Plant	PtEverglades U2	31200	6.1%	15,804,017.73	15,804,017.73
	02 - Steam Generation Plant	PtEverglades U2	31500	2.1%	638,470.14	638,470.14
	02 - Steam Generation Plant	PtEverglades U3	31100	2.6%	4,812,793.71	4,812,793.71
	02 - Steam Generation Plant	PtEverglades U3	31200	4.0%	16,125,920.25	16,125,920.25
	02 - Steam Generation Plant	PtEverglades U3	31500	2.2%	2,531,026.34	2,531,026.34
	02 - Steam Generation Plant	PtEverglades U4	31200	3.6%	25,326,653.05	25,326,653.05
	02 - Steam Generation Plant	PtEverglades U4	31500	2.1%	3,091,243.18	3,091,243.18
		Total For Project 25 - PPE ESP Technology			81,840,718.63	81,840,718.63
31 - Clean Air Interstate Rule (CAIR)						
	02 - Steam Generation Plant	Manatee Comm	31400	0.4%	0.00	999,999.00
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	0.00	1,200,000.00
	02 - Steam Generation Plant	Martin Comm	31400	0.8%	0.00	1,299,999.00
	02 - Steam Generation Plant	Martin U1	31200	1.8%	0.00	10,807,500.00
	02 - Steam Generation Plant	Martin U1	31400	1.3%	0.00	1,400,001.00
	02 - Steam Generation Plant	Martin U1	31600	0.6%	0.00	7,749,999.00
	02 - Steam Generation Plant	SJRPP U2	31200	2.3%	0.00	20,675,092.04
	05 - Other Generation Plant	FtLauderdale GTs	34300	2.2%	132,333.00	132,333.00
	05 - Other Generation Plant	FtMyers GTs	34300	3.1%	132,333.00	132,333.00
	05 - Other Generation Plant	PtEverglades GTs	34300	2.6%	132,333.00	132,333.00
		Total For Project 31 - Clean Air Interstate Rule (CAIR)			396,999.00	44,529,589.04
35 - Martin Drinking Water System Compliance						
	02 - Steam Generation Plant	Martin Comm	31100	1.7%	0.00	144,000.00
		Total For Project 35 - Martin Drinking Water System Compliance			0.00	144,000.00
				Total For All Projects	180,635,325.32	233,085,298.36

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Air Operating Permit Fees - O & M
Project No. 1

Project Description:
The Clean Air Act Amendments of 1990, Public Law 101-549, and Florida Statutes 403.0872, require each major source of air pollution to pay an annual license fee. The amount of the fee is based on each source's previous year's emissions. It is calculated by multiplying the applicable annual operation license fee factor ($25 per ton for both Florida and Georgia) by the tons of each air pollutant emitted by the unit during the previous year and regulated in each unit's air operating permit, up to a total of 4,000 tons per pollutant. The major regulated pollutants at the present time are sulfur dioxide (SO2), nitrogen oxides (NOx) 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, 2007 to December 31, 2007)
The monthly fees for 2006 emissions at Scherer have been paid and continue to be paid in 2007. 2006 air operating permit fees for the Florida facilities were calculated in January 2007 utilizing 2006 operating information. They were paid to the FDEP in February, 2007.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is estimated to be $129,094 or 6.6% lower than previously projected. This variance is primarily due to higher gas fuel usage across the Florida Fleet due to the higher costs of # 6 residual oil. Permit fees are based on emissions, which are proportionate to the type of fuel used at each Florida Facility. Utilizing pipeline natural gas in lieu of combusting # 6 residual oil significantly reduces SO2, Particulate Matter (PM) & NOx emissions.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
The monthly fees for 2006 emissions at Scherer have been paid and continue to be paid in 2007. 2006 air operating permit fees for the Florida facilities were calculated in January 2007 utilizing 2006 operating information. They were paid to the FDEP in February 2007.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project expenditures for the period January 2008 through December 2008 are expected to be $1,965,264.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Continuous Emission Monitoring Systems (CEMS) - 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 SO2, NOx, CO, Carbon Dioxide (CO2/O2) emissions, as well as opacity data from affected air pollution sources. FPL has 57 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 and opacity. These Systems continuously 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 are ongoing activity which follow the Title IV CEMS Quality Assurance Program Manual.

Project Accomplishments:
(January 1, 2007 to June 1, 2007)
Relative Accuracy Tests and Linearity Tests continue to be performed as scheduled. QA/QC maintenance continues to be performed on the analyzers per the requirements of the Title IV CEM Quality Assurance Program Manual. Calibration span gases and CEMS required parts continue to be purchased. In addition, analysis of fuel oil for sulfur content, heat of combustion and carbon continues to be performed per the requirements of 40 CFR Part 75, Appendix D. CEMS 24/7 Software Support contract with General Electric (CEMS NETDAHS) continues to be maintained to ensure integrity of the CEMS Systems and to ensure compliance with EPA and State Agencies.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is currently estimated to be $63,617 or 8.5% lower than previously projected primarily due to fewer than expected purchases of CEMS spare parts for the remainder of 2007.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
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:
(January 1, 2008 to December 31, 2008)
Estimated project expenditures for the period January 2008 through December 2008 are expected to be $751,782.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Maintenance of Stationary Above Ground Fuel Storage Tanks - O&M
Project No. 5a

Project Description:
Florida Administrative Code (F.A.C.) Chapter 62-761, previously 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

The required base line internal inspections have been completed and the future internal inspections have been scheduled based on the established corrosion rate of the tank bottoms. Future costs will be incurred for required 5 year external inspections and repairs. TMT Tanks 1271/A, 1271/B (each with the capacity 500,000 bbls), purge tank (capacity 37,000 bbls), PFM Light Oil Tank #1 (capacity 100,000 bbls) and PFM Light oil tank # 2 are due for API in-service inspection. Inspection of TMT fuel storage tanks were conducted by TEAM on January 2007 and PFM fuel storage tanks were conducted by TEAM on February 2007. No discrepancies were reported and all fuel storage tanks appear to be suitable for continued services. The next due dates for external inspection was determined by API certified inspector after 5 years.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
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 2007 tank registration fees have been paid.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is estimated to be $41,805 or 1.9% higher than previously projected. This variance primarily due to the high demand in the tank repair market, which has increased the cost of labor.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
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:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures for the period January 2008 through December 2008 are expected to be $677,072.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Oil Spill Cleanup/Response Equipment - O&M
Project No. 8a

Project Description:
The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
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, 2007 to December 31, 2007)
The variance in project expenditures is estimated to be $183 or 0.1% lower than originally anticipated.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
This is an ongoing project. Each reporting period will include ongoing maintenance of all oil spill equipment in accordance with OPA 90. Additionally, following a formal assessment of the oil spill program, FPL retained a contractor to perform the mandated OSRO (oil spill removal organization) function. This contractor will also perform required maintenance on the oil spill equipment at all of the power plants as well as perform a required annual equipment deployment drill at these facilities. FPL has 1) retained a spill management company to assist in corporate-level responses, 2) improved/enhanced the Fleet's ability to mobilize spill equipment (specifically boats), and 3) began certifying all oil spill response members in the NIMS mandated Incident Command System (ICS).

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures for the period January 2008 through December 2008 are expected to be $276,800.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: RCRA Corrective Action - O & M
Project No. 13

Project Description:
Under the Hazardous and Solid Waste Amendments of 1984 (amending the Resource Conservation and Recovery Act, or RCRA), the U.S. EPA has the authority to require hazardous waste treatment facilities to investigate whether there have been releases of hazardous waste or constituents from non-regulated units on the facility site. If contamination is found to be present at levels that represent a threat to human health or the environment, the facility operator can be required to undertake "corrective action" to remediate the contamination. In April 1994, the U.S. EPA advised FPL that it intended to initiate RCRA Facility Assessments (RFA's) at FPL's nine former hazardous waste treatment facility sites. The RFA is the first step in the RCRA Corrective Action process. At a minimum, FPL will be responding to the agency's requests for information concerning the operation of these power plants, their waste streams, their former hazardous waste treatment facilities, and their non-regulated Solid Waste Management Units (SWMU's). FPL may also conduct assessments of human health risks 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, 2007 to December 31, 2007)
EPA and the FDEP have agreed that no further action is required at the Fort Myers, Cape Canaveral, 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. The EPA withdrew the 3007 order. In January, 2005, FPL entered into a bilateral Agreement with the FDEP to complete the assessments at the Sanford, Manatee, Saint Lucie, and Turkey Point Plants. During 2005, FPL prepared documents for the Sanford Plant that were submitted to the FDEP. In March 2007, a draft Facility Evaluation Report was received and reviewed by FPL. The draft report was returned to FDEP and a final report was received in the second quarter of 2007, awarding no further action for the Sanford Power Plant. Document preparation for the Manatee Plant was completed during third quarter 2007 for submitted to FDEP, with a Facility Evaluation site took place in the third quarter of 2007 and the site is awaiting the final report from the FDEP. Site preparation was completed at Manatee Plant and is currently scheduled to begin at Turkey Point Plant during third quarter 2007. Site preparation work is underway at Manatee Plant and is currently scheduled to begin at Turkey Point Plant during third quarter 2007. Site work for Turkey Point may be deferred to 2008 dependent upon FDEP scheduling.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is estimated to be $3,706, or 3.7% higher than originally projected. This variance reflects additional charges from work at the Sanford plant.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
This is an ongoing project. The Manatee Plant Visual Site Inspection (referred to as a Facility Evaluation in the Agreement with the FDEP) date has been completed and the site is waiting for the final FDEP response. Turkey Point is next to undergo the Facility Evaluation. No further action is required at Ft. Myers, Cape Canaveral, Martin or Sanford Power Plants. No further action is required at the Putnam Plant except for some petroleum clean-up that is being addressed pursuant to a FDEP program.

Project Projection:
(January 1, 2008 to December 31, 2008)
Estimated project expenditures for the period of January 2008 through December 2008 are expected to be $122,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: NPDES Permit Fees - O & M
Project No. 14

Project Description:
In compliance with State of Florida Rule 62-4.052, 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.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
All of the NPDES permit fees were paid to FDEP.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is estimated to be $500 or 0.4% lower than projected.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
All of the NPDES permit fees were paid to FDEP.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project expenditures for the period January 2008 through December 2008 are expected to be $154,900. The new permit will be due in 2011.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Disposal of Noncontainerized Liquid Waste - O&M
Project No. 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, 2007 to December 31, 2007)
Ash work has been completed at Riviera Beach, Port Everglades, Martin and Sanford Plants. Remaining on the schedule for 2007 are Cape Canaveral in October and Turkey Point in August. Approximately $23,000 will be spent on Maintenance Costs to replace worn hoses, filter cloths and a pump.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is estimated to be $22,368 or 8.3% higher than projected. This variance is primarily due to greater than anticipated ash accumulation in the storage basins. As a result of the increase in ash material to be handled for removal, the site incurred extra expenses due to the use of additional moving equipment to support the job. Also, the time associated with the contractor completing the job contributed to the increases in manpower hours. This increase in time and materials to clean out ash accumulation ultimately resulted in increased expenditures.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
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:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures for the period January 2008 through December 2008 are expected to be $299,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Substation Pollutant Discharge Prevention & Removal - O&M
Project No. 19a, 19b, 19c

Project Description:
Florida Statute Chapter 376 Pollutant Discharge Prevention and Removal requires that any person discharging a pollutant, defined as any commodity made from oil or gas, shall immediately undertake to contain, remove and abate the discharge to the satisfaction of the department. Florida Statute Chapter 403 holds it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. Additionally, the majority of activities will be conducted in Dade and Broward counties which adhere to county regulations as defined in municipal codes. This project includes the prevention and removal of pollutant discharges at FPL substations and will prevent further environmental degradation.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
Plan development started in 1997 and fieldwork is planned to continue. The majority of the completed work has been in Dade, Broward and Palm Beach counties. Encapsulation work is projected for completion by the years end. The regasketing work continues. Environmental remediation work continues in Miami-Dade County.

A total of 709 transformer locations have been remediated since 1997. A total of 432 transformers have been regasketed and 904 transformers have been encapsulated. Additionally, 501 transmission breakers, 251 distribution breakers, and 336 distribution regulators have been encapsulated.

Out of a total of 65 substation sites under regulatory review by Miami-Dade County Environmental Resources Management ("DERM"), 58 sites have obtained a regulatory exclusion or regulatory closure. In 2005, FPL obtained no further action with conditions by recording restrictive covenants for 13 substation sites with lead levels in soils above residential exposure limits. In 2006, after initial remedial efforts, DERM accepted closure at 15 substation sites that were under review for lead levels in soils above regulatory limits. In 2007, DERM accepted and additional regulatory closure for a substation site under review for lead levels in soils above regulatory limits. FPL was able to avoid regulatory review for 35 substations with arsenic levels in soils above regulatory limits, by application for and receipt of an agricultural exclusion for these substation locations. However, there are six substations where elevated levels of arsenic were found in the groundwater and environmental remediation continues at these substation sites. One substation with lead and arsenic levels in soils above cleanup target levels remains under regulatory review.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
Project expenditures are estimated to be:
- 19a The variance in project expenditures is estimated to be $5,094 or 0.4% higher than projected.
- 19b The variance in project expenditures is estimated to be $108,161 or 138.4% higher than projected. In the first and second quarter additional transmission transformers requiring leak repair or regasket work activities were identified and scheduled to be worked during the remainder of 2007.
- 19c No variance is anticipated.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
Miami-Dade County DERM determined that soil and groundwater remediation were required by FPL to resolve contamination issues at substation locations where arsenic levels in groundwater were determined by laboratory analysis to exceed groundwater cleanup target levels. The arsenic in soils and groundwater is being addressed at six substation locations. Lead and arsenic levels in soils are being addressed at one site in Miami-Dade County.

The regasketing phase of the project continues while the encapsulation phase is projected for completion at the end of this year.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures for the period January 2008 through December 2008 are expected to be:
- 19a $967,700
- 19b 356,500
- 19c ($560,232)

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Wastewater/Stormwater Discharge Elimination & Reuse - O&M
Project No. 20

Project Description:
Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants, and the Dade County DERM requires Turkey Point and Cutler Plant wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan Dade County.

In order to address these requirements, FPL has undertaken a multifaceted project which includes activities such as ash basin lining, installation of retention tanks, tank coating, sump construction, installation of pumps, motor, and piping, boiler blowdown recovery, site preparation, separation of stormwater and ashwater systems, separation of potable and service water systems, and the associated engineering and design work to implement these projects.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
The project is on hold due to the Pt. Everglades ESP Project.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
The project is on hold due to the Pt. Everglades ESP Project.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures for the period January 2008 through December 2008 are expected to be $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Turtle Net – O&M
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.

The existing net is in need of maintenance. To facilitate this work, a temporary net will be situated to allow removal of the existing net. The new net having been properly coated for UV protection and anti-fouling will be installed replacing the existing net. The existing net will be repaired and maintained as a spare to allow rotation of the nets for future maintenance.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
FPL expects to purchase the new 5-inch net in the last quarter of 2007. The current net will be sent to the manufacturer for re-coating during the first quarter of 2008, at which time the new net will be installed.

Project Fiscal Expenditures:
(January 1, 2007 – December 31, 2007)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
The existing turtle net will be removed to be recoated and the new net will be installed in the interim. The new net will serve as a backup.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures for the period January 2008 through December 2008 are $10,000 for recoating of existing net.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pipeline Integrity Management (PIM) – O&M
Project No. 22

Project Description:
FPL is required to develop a written pipeline integrity management program for its hazardous liquid pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
The baseline assessments were undertaken for the Manatee 16" pipeline and associated evaluation has been completed. Two additional digs one on Manatee 16" and the other on Martin Plant 20" gas pipelines and two or three digs on Martin 30" pipeline will be completed by the year end. Martin Terminal 30" pipeline is scheduled for smart pig this year to determine the corrosion rate by comparing the tool's data to previous run dated 2004 for future appropriate countermeasures. Severe corrosion at the girth weld joints were detected in 2004 run. A rehabilitation project of cathodic protection test stations on all corporate pipelines (Martin 30", 18", 20", 6" and Manatee 30", 16") were completed early this year.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is estimated to be $400,354 or 47.7% lower than projected. The estimated under-run in this project is primarily due to two reasons: 1) very competitive bids were received and the work was done at a lower that anticipated budget for both the cathodic protection jobs and the 30" pipeline inspection and 2) the work was completed prior to the rainy season and additional costs associated with dealing with potential ground water issues were avoided, thus resulting in cost savings.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
This is an ongoing project. Required DOT digs, assessments and evaluations will be conducted as required. (As a DOT requirement after each in-line-inspection – smart pig – the data regarding the anomalies, dents, need to be validated by performing two, three and may be even more as necessary confirmatory digs and conducting the direct assessment and inspection on the location of the detected anomalies. UTM's and magnetic particle testing is a part of these direct assessment. The number of confirmatory digs performed on corporate pipelines so far after the in-line-inspection are as follows: PMR 20" two digs. There is a plan to conduct two more digs on Martin 20", Manatee 16" and three digs on Martin 30" pipelines (total 5 digs).

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures for the period January 2008 through December 2008 are expected to be $260,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: SPCC (Spill Prevention, Control, and Countermeasures) - O&M
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, 2007 to December 31, 2007)
The Facility Response Plans (FRP), which contain the SPCC plans, are scheduled to be issued by the end of the year. This will include drawing updates and necessary reviews. It is anticipated that the project will have all the required facility upgrades identified by the end of the year. The Engineering package for the SPCC secondary containment modifications at the Unit 3 Diesel Oil Storage Tank has been issued and installation of an impervious surface and installation of a pump to remove rainwater began in June 2006. Work at the Land Utilization fueling area is nearing completion with application of an impervious coating on the berm.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is estimated to be $220,753, or 237.4% higher than projected. Additional required upgrades at the Sanford Plant, Martin Plant, Martin Terminal, Port Everglades Plant, Port Everglades Terminal, Manatee Plant, Manatee Terminal, Turkey Point Plant Units 1 and 2, and the Cape Canaveral Plant were identified during development of the plans. Additional engineering was required to develop conceptual designs and cost estimates for the upgrades, which are scheduled for implementation in 2008. These upgrades were not anticipated at the time FPL filed its original projections for 2007.

At Turkey Point Units 3 and 4, longer than estimated construction durations and the replacement of degraded gas tanks that did not pass Miami-Dade County inspections contributed to the variance. The original projections planned to utilize existing tanks. Once the work began, the tanks were discovered to be degraded and needed to be replaced.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
The SPCC project plant has been modified to replacement of underground tanks.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures for the period January 2008 through December 2008 are expected to be $387,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Reburn – 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, 2007 to December 31, 2007)
Installation of the Unit 1 & 2 reburn equipment is complete. The units has been started up and are operating and are currently undergoing process optimization of the new systems to ensure maximum emissions reductions. The PMT Reburn O&M ECRC dollars cover all burner maintenance costs associated with the project.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is estimated to be $41,868 or 8.4% lower than projected. The variance is primarily due to limited maintenance time available during the May and June high load period.

Project Progress Summary:
(January 2007 - December 2007)
Unit 1 & Unit 2 are operating as referenced above.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project expenditures for the period January 2008 through December 2008 are expected to be $500,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pt. Everglades ESP Technology – O&M
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, 2007 to December 31, 2007)
The engineering design for Units 1–4 was completed in 2004. Units 1, 2, and 4 were completed and operational in 2005 and 2006 (O&M activities started in April 2005 for this project).

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is estimated to be $872,150 or 41.4% lower than projected. Fuel economics to date have dictated that the units at the Port Everglades Plant be run on gas because it is less expensive. Therefore, the ESPs have not had to be operated as much as was initially predicted for 2007, which reduced the equipment deterioration and generated significantly less ash for disposal.

Project Progress Summary:
(January 1, 2007 - December 31, 2007)
Construction on the Unit 3 electrostatic precipitator was completed in spring 2007 as the Unit went operational in May 2007. Therefore, at this time, all four ESP's (Units 1 through 4) have construction activities completed and are operational.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project expenditures for the period January 2008 through December 2008 are expected to be $2,352,384.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: UST Replacement/Removal – O&M
Project No. 26

Project Description:
The Florida Administrative Code (FAC) Chapter 62-761.500, dated July 13, 1998, requires the removal or replacement of existing Category-A and Category-B storage tank systems with systems meeting the standards of Category-C storage tank systems by December 31, 2009. UST Category-A tanks are single-walled tanks or underground single-walled piping with no secondary containment that was installed before June 30, 1992.

UST Category-B tanks are 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 and AST Category-C tanks under F.A.C. 62-761.500 are tanks that shall have some or all of the following; a double wall, be made of fiberglass, have exterior coatings that protect the tank from external corrosion, secondary containment (e.g., concrete walls and floor) for the tank and the piping, and overfill protection.

FPL has six Category-A and two Category-B Storage Tank Systems that must be removed or replaced in order to meet the performance standards of Rule 61-761.500. In 2004 FPL will replace the two single-walled USTs located at the Turkey Point Nuclear Plant Units 1 and 2 with ASTs providing secondary containment (concrete walls and floor) surrounding the tanks. Also in 2004, FPL will remove one single-walled UST located at the Ft. Lauderdale Plant and will not replace the tank. In 2005-2006 FPL will replace the single-walled USTs located at the Area Office Broward (one UST in 2005), Customer Service East Office (one UST in 2006), Juno Beach Office (one UST in 2005), and General Office (2 USTs in 2005), with double-walled tanks providing electronic leak detection. Additionally, the AST to be installed at the Area Broward Office will be concrete vaulted.

The removal and replacement of the USTs will be performed by outside contractors. Additionally, closure assessments will be performed in accordance with 62-761.800 and closure assessment reports will be submitted to local Counties, and the Department of Environmental Services (DEP).

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
There were no activities in 2007.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
Project expenditures are for 2007 are $6 due to a carryover of charges from 2006.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
Initial review of the scope of work has been completed.

Project Projections:
(January 1, 2008 to December 31, 2008)
There are no activities planned for 2008.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Lowest Quality Water Source (LQWS) – O&M
Project No. 27

Project Description:
Section 366.8255 of the Florida Statutes provides for the recovery through the ECRC of "environmental compliance costs" which are costs incurred in complying with "environmental rules or regulations." 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, 2007 to December 31, 2007)
The project at the Sanford Plant is currently operational.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is $161,771 or 30.5% lower than previously projected. The Wastewater Permit for the Cape Canaveral Plant was issued by the Florida Department of Environmental Protection. However, there were delays due to water quality technical issues associated with the treatment systems and reclaimed water was not used at the plant; therefore, there was not a cost for the additional water treatment that would be required in order to use reclaimed water.

Project Progress Summary:
(January 1, 2007 - December 31, 2007)
The project at the Sanford Plant is currently operational. There are delays due to water quality technical issues associated with the treatment systems for the project at the Cape Canaveral Plant.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures for the period January 2008 through December 2008 are expected to be $300,900 for the Sanford Plant.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: CWA 316(b) Phase II Rule - O&M
Project No. 28

Project Description:
The Phase II Rule implements section 316 (b) of the Clean Water Act (CWA) for certain existing power plants that employ a cooling water intake structure and that withdraw 50 million gallons per day (MGD) or more of water from rivers, streams, lakes, reservoirs, estuaries, oceans or other waters of the United States (WUS) for cooling purposes. The Phase II Rule establishes national requirements applicable to, and that reflect the best technology available (BTA) for, the location, design, construction and capacity of existing cooling water intake structures (CWIS) to minimize adverse environmental impact. The Phase II Rule has implications at the following FPL facilities: Cape Canaveral, Cutler, Fort Myers, Ft. Lauderdale, Port Everglades, Riviera, Sanford, Martin, Manatee and St. Lucie Power Plants.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
The Proposal for Information Collection (PIC) – the first regulatory requirement of the Phase II Rule – has been submitted for Cape Canaveral, Cutler, Fort Myers, Ft. Lauderdale, Port Everglades, Riviera, Sanford and St. Lucie Power Plants. Compliance demonstration documents have been submitted for Martin and Manatee plants, as these plants already meet the requirements of the Phase II Rule.

Project Fiscal Expenditures:
(January 1, 2007 to June 30, 2007)
Project expenditures are estimated to be $1,018,188 (43.4%) lower than projected. This variance is primarily due to economies of scale achieved by the use of one contractor to perform the necessary work. Original estimates included the use of three contractors.

Project Progress Summary:
(January 1, 2007 to June 30, 2007)
The 316(b) project is on schedule for each of the plants. The Proposal for Information Collection (PIC) has been submitted for Cape Canaveral, Cutler, Fort Myers, Ft. Lauderdale, Port Everglades, Riviera, Sanford and St. Lucie Power Plants. Compliance demonstration documents have been submitted for Martin and Manatee plants. One year biological sampling programs have been completed for Cutler, Fort Myers, Port Everglades, Riviera, and St. Lucie Power Plants – with the Cape Canaveral Plant expected to be completed in November 2007. Currently we are analyzing the biological data to determine if there are impingement and entrainment impacts at each plant. High level technology reviews are also being conducted at each of the facilities using the biological data.

Project Projections:
(January 1, 2008 to December 2008)
Estimated project fiscal expenditures for the period January 2008 through December 2008 are expected to be $1,433,728.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: SCR Consumables - O&M
Project No. 29

Project Description:
The Manatee Unit 3 and Martin Unit 8 Expansion Project Final Orders of Certification under the Florida Power Plant Siting Act and the PSD Air Construction Permit require the installation of SCRs on each of the plants' four Heat Recovery System Generators (HRSG) for the control of nitrogen oxide (NOx) emissions. The Florida Department of Environmental Protection (FDEP) made the determination that the SCR system is considered Best Available Control Technology (BACT) for these types of units, with concurrence from the U.S. Environmental Protection Agency (EPA). The operation of the SCR will cause FPL to incur O&M costs for certain products that are consumed in the SCRs. These include anhydrous ammonia, calibration gases, and equipment wear parts requiring periodic replacement such as controllers, ammonia detectors, heaters, pressure relief valves, dilution air blower components, NOX control analyzers and components.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
The SCR systems are operational on both Manatee Unit 3 and Martin Unit 8.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is estimated to be $34,685 or 15.4% higher than projected. The Manatee and Martin Plants are expected to operate at high capacity factors for the remaining months of the year thereby increasing the amount of consumables used. Additionally, catalyst sampling and testing expenses were higher than originally projected.

Project Progress Summary:
(January 1, 2007- December 31, 2007)
The Manatee and Martin Plants are expected to operate at high capacity factors for the remaining months of the year thereby increasing the amount of consumables used.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures for the period January 2008 through December 2008 are expected to be $855,200.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Hydrobiological Monitoring Program (HBMP) - O&M
Project No. 30

Project Description:
The Hydrobiological Monitoring Program is required by the Water Management District in the Conditions of Certification for the new Manatee Unit 3. The program involves the data collection of river chemistry, flow and vegetation conditions to demonstrate that the plant's withdrawals do not impact the environment in and along the river. The Hydrobiological Monitoring Program is a 10 year study which started in 2003 during the construction phase of Unit 3 and will be completed in 2013.

Project Accomplishments:
(January. 1, 2007 to December 31, 2007)
Continue with river monitoring, calibration, maintenance and data collection. Data summary and interpretive report submitted May 2007. Vegetative mapping, aerial photography and mapping is due to be conducted in October 2007. Additional studies will be conducted during summer due to drought conditions and use of Emergency Diversion Schedule.

Project Fiscal Expenditures:
(January 1, 2007 to May 31, 2007)
The variance in project expenditures is estimated to be $17,895 or 71.6% higher than projected. The variance is primarily due to additional monitoring required due to unexpected drought conditions. The permit requires that while on the Emergency Diversion Curves, additional river monitoring is conducted and a report is submitted.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
This is an ongoing project. During 2007 the data summary and interpretive report were submitted.

Project Projections:
(January 1, 2008 to December 31, 2008)
Project estimates for January 2008 through December 2008 are expected to be $40,400.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: CAIR – O&M
Project No. 31

Project Description:
The CAIR Project was initiated to implement strategies to comply with CAIR Annual and Ozone Season NOx emissions requirements. The CAIR project to date has included the Black & Veatch (B&V) study of FPL's control and allowance management options, an engineering study conducted by Aptech for the reliable cycling of the 800 MW units, and a review of CEMS monitoring changes required for the peaking gas turbine units. The 800 MW Cycling Project was added to CAIR after 2006 submittal. Aptech Engineering provided engineering services for the first phase of a multiphase scope of work that will assure that the operating reliability is maintained in the new operating mode. FPL anticipates changing the operating mode of its four 800 MW units at Martin and Manatee Plants. The "study cost" so far to Aptech Engineering have been paid. They have identified several countermeasures that are being prioritized and scheduled for implementation in 2008 – 2011. The update to the Gas Turbine Peaking Unit CEMS requirements identified the need to implement a revised CEMS monitoring program for those units which will now require CEMS under the CAIR program requirements. FPL has determined that the implementation of the Low Mass Emissions option under 40 CFR Part 75 as the preferred option. The CEMS installations will require emissions testing of representative units and the procurement and installation of a Continuous Emissions Monitor at the Port Everglades GTs, Lauderdale GTs and Fort Myers GTs.

Project Accomplishments:
(January 1, 2006 to July 1, 2007)
- Completed B & V study of CAIR compliance options
- Completed 800 MW Cycling Engineering Study

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in project expenditures is estimated to be $156,047 or 70.9% higher than projected. This variance is due to costs associated with the 800 MW unit cycling study, which was not included in the original estimates for 2007.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
Evaluation of CAIR compliance options identified the 800 MW cycling project as most cost effective control option identified for compliance with CAIR. Project scope, outage planning and activities have been identified for implementation at the Martin and Manatee 800 MW units. The GT CEMS project has identified the hardware components which will be required and modifications which must be made to emission stacks of the representative units at each GT site.

Project Projections:
(January 1, 2008 to December 31, 2008)
Project estimates for January 2008 through December 2008 are expected to be $1,795,004. Projections are likely to change as a result of contractual guarantees related to necessary overhaul schedules, component and materials costs and labor estimates.

The GT Peaking project has projected an estimated total cost at $386,000 for the Jan 2008 through Dec 2008 period.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: BART Project – O&M
Project No. 32

Project Description:
Conduct air dispersion modeling to determine the visibility impacts to Federally Mandated Class 1 Areas (National Parks, National Wilderness Areas, etc.) from FPL's BART-Eligible units. The Regional Haze Rule, renamed the Clean Air Visibility Rule, (CAVR) mandates that certain vintage electric generating units (ca. 1962-1977) install Best Available Retrofit Technology (BART) if it is shown, via modeling that a unit causes or contributes to visibility impairment in any Class 1 Area.

Project Accomplishments:
(January. 1, 2007 to December 31, 2007)

- Compile Emissions Inventory of BART-Eligible sources – Complete May 2006
- Perform modeling - First round complete June 2006
- Conduct BART Control Technology Analysis – Pending
- Prepare BART Application Packages – Fall 2006

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
Project expenditures are estimated to be $3,397, whereas FPL did not anticipate any 2007 expenditures for this project originally. The DEP requested additional information on FPL's BART Determination for Turkey Point Units 1 and 2, which necessitated the use of a contractor. This activity was not anticipated at the time FPL filed its original projections for 2007.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
BART Application for exempt facilities (PCC, PMR, PMT, PPE, PRV) submitted to FDEP 1/31/07. BART Determination for PTF submitted to FDEP 1/31/07. FDEP requested additional information on PTF 2/26/07 which necessitated additional Golder support. Response to FDEP additional information submitted to FDEP 5/3/07.

Project Projections:
(January 1, 2008 to December 31, 2008)
Project estimates for January 2008 through December 2008 are expected to be zero.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Cooling Water System Inspection and Maintenance – O&M
Project No. 34

Project Description:
The purpose of the proposed St. Lucie Plant Cooling Water System Inspection and Maintenance Project (the "Project") is to inspect and, as necessary, maintain the cooling water system at FPL's St. Lucie nuclear plant (the "Cooling System") such that it minimizes injuries and/or deaths of endangered species and thus helps FPL to remain in compliance with the federal Endangered Species Act, 16 U.S.C. Section 1531, et seq. (the "ESA") The St. Lucie Plant is an electric generating station on Hutchinson Island in St. Lucie County, Florida. The plant consists of two nuclear-fueled 850 net MWe units, both of which use the Atlantic Ocean as a source of water for once-through condenser cooling. This cooling water is supplied to the units via the Cooling System. The St. Lucie Plant cannot operate without the Cooling System. Compliance with the ESA is a condition to the operation of the St. Lucie Plant. Inspection and cleaning of the intake pipes is an "environmental compliance cost" under section 366.8255, Florida Statutes. The specific "environmental law or regulation" requiring inspection and cleaning of the intake pipes are terms and conditions that will be imposed pursuant to a Biological Opinion ("BO") that is to be issued by the National Oceanic and Atmospheric Administration ("NOAA") pursuant to section 7 of the ESA. NOAA will finalize the BO in 2007. NOAA sent the Nuclear Regulatory Commission ("NRC") a letter dated December 19, 2006, confirming its intent to issue the BO and stating the requirements that will be imposed pursuant to the BO with respect to inspection and cleaning of the intake pipes.

Project Accomplishments:
(January 8, 2007 thru December 31, 2007)
Inspections have been completed on all intake and discharge lines. Currently we are reviewing bids for the cleaning of the intake lines for SL2 fall 2007. We expect the cleaning to be completed prior to the end of the year. Should the cleaning not be completed in 2007 we will be continuing in the SL1 outage.

Project Fiscal Expenditures:
(January 8, 2007 to December 31, 2007)
Per FPL's petition filed on January 8, 2007, project fiscal expenditures are estimated to be $8,088,753. Therefore, this estimate was not included in FPL's original projections filed on October 13, 2006.

Project Progress Summary:
(January 8, 2007 to December 31, 2007)
The inspections of the ocean intakes and discharges were completed during the SL1 Spring 2007 outage in April and May. Cleaning of select areas of the three ocean intake pipes and velocity caps is scheduled for the SL2 outage planned for the Fall 2007, October 1- Dec 25.

Project Projections:
(January 1, 2008 to December 31, 2008)
Project estimates for January 2008 through December 2008 are expected to be $442,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Low NOx Burner Technology – Capital
Project No. 2

Project Description:
Under Title I of the Clean Air Act Amendments of 1990, Public Law 101-349, utilities with units located in areas designated as "non-attainment" for ozone will be required to reduce NO_x emissions. The Dade, Broward and Palm Beach county areas were classified as "moderate non-attainment" by the EPA. FPL has six units in this affected area.

LNBT meets the requirement to reduce NO_x emissions by delaying the mixing of the fuel and air at the burner, creating a staged combustion process along the length of the flame. NO_x formation is reduced because peak flame temperatures and availability of oxygen for combustion is reduced in the initial stages.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
All six units are in service and operational.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in depreciation and return is $23,548 or 2.5% lower than projected. Two Burner Management System Operator Stations were retired at the Turkey Point Plant were retired, which were not included in the original projections.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
Dade, Broward and Palm Beach Counties have now been re-designated as "attainment" for ozone with air quality maintenance plans. This re-designation 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:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $848,325.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Continuous Emission Monitoring System (CEMS) – Capital
Project No. 3b

Project Description:
The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping and reporting of SO_2, NO_x and carbon dioxide (CO_2) emissions, as well as volumetric flow, heat input, and opacity data from affected air pollution sources. FPL has 36 units which are affected and which have installed CEMS to comply with these requirements.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMS and specific requirements for the monitoring of pollutants, opacity, heat input, and volumetric flow. These regulations are very comprehensive and specific as to the requirements for CEMS, and in essence, they define the components needed and their configuration. Periodically, these systems extract and analyze gaseous samples for each power plant stack and have automated data acquisition and reporting capability.

Project Accomplishments (January 1, 2007 to December 31, 2007)
The 2006 Continuous Emission Monitoring System Capital Project necessary to replace the CEMS CO2 emission analyzers at FPL generating units is being postponed until 2007/2008 due to delays in completing pilot studies at FPL's Riviera and Port Everglades sites.

Project Fiscal Expenditures: (January 1, 2007 to December 31, 2007)
The variance in depreciation and return is $60,189, or 5.5% lower than projected. This variance is primarily due to the procurement of a much lower cost per unit pricing from the vendor (California Analytical). In addition, several installations and in-service dates shifted from 2007 to 2008 due to equipment availability delays and schedule changes.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
Due to delays in initially acquiring the emission equipment from the CAI Manufacturer, Martin 1/2 and Manatee 2 originally scheduled for 2007 was pushed to 2008. In 2007, FPL will place in service seventeen (17) CO2 analyzers at Cutler, Port Everglades 4, Manatee 1, Martin 3/4, Sanford 3, Putnam 1/2 and Lauderdale 4/5 and the remaining twelve (12) will be installed and placed in service in 2008. In addition, all CO2 & So2 equipment will be purchased and cash flowed in 2007. This Project also includes twelve (12) SO2 analyzer replacements at Port Everglades, Riviera, Martin 1/2, Cape Canaveral and Turkey Point. Port Everglades 4 has been replaced and is currently in service with the remaining to be installed in 2008.

CEMS server replacement will be completed for FPL in 2007, with Riviera, Port Everglades and Lauderdale 5 completed to date.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $1,020,109.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Clean Closure Equivalency – Capital
Project No. 4b

Project Description:
In compliance with 40 CFR 270.1(c)(5) and (6), FPL developed CCED's for nine FPL power plants to demonstrate to the U.S. EPA that no hazardous waste or hazardous constituents remain in the soil or water beneath the basins which had been used in the past to treat corrosive hazardous waste. The basins, which are still operational as part of the wastewater treatment systems at these plants, are no longer used to treat hazardous waste.

To demonstrate clean closure, soil sampling and ground water monitoring plans, implementation schedules, and related reports must be submitted to the EPA. Capital costs are for the installation of monitoring wells (typically four per site) necessary to collect ground water samples for analysis.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in depreciation and return is $158 or 3.8% lower than projected.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
All activities are complete.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $3,840.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Maintenance of Stationary Above Ground Fuel Storage Tanks – Capital
Project No. 5b

Project Description:
Florida Administrative Code (F.A.C.) Chapter 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

The capital project associated with complying with the new standards includes the installation of items for each tank such as liners, cathodic projection systems and tank high-level alarms.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
An 8" and 12" underground fuel oil pipe in the Port of Palm Beach and an above ground 12" fuel oil pipeline on the PRV plant property were removed.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in depreciation and return is $74,027 or 4.0% lower than projected.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
An 8" and 12" underground fuel oil pipe in the Port of Palm Beach and an above ground 12" fuel oil pipeline on the PRV plant property were removed.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 *are expected to be* $1,700,056.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Relocate Turbine Lube Oil Underground Piping to Above Ground – Capital
Project No. 7

Project Description:
In accordance with criteria contained in Chapter 62-762 of the Florida Administrative Code (F.A.C.) for storage of pollutants, FPL initiated the replacement of underground Turbine Lube Oil piping to above ground installations at the St. Lucie Nuclear Power Plant.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in depreciation and return is $74 or 4.4% lower than projected.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
This project is complete.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $1,558.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Oil Spill Cleanup/Response Equipment – Capital
Project No. 8b

Project Description:
The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

Project Accomplishments
(January 1, 2007 to December 31, 2007)
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, 2007 to December 31, 2007)
The variance in depreciation and return is $1,757 or 2.4% lower than projected.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
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:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $84,497.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Relocate Storm Water Runoff – Capital
Project No. 10

Project Description:
The new National Pollutant Discharge Elimination System (NPDES) permit, Permit No. FL0002206, for the St. Lucie Plant, issued by the United States Environmental Protection Agency contains new effluent discharge limitations for industrial-related storm water from the paint and land utilization building areas. The new requirements become effective on January 1, 1994. As a result of these new requirements, the effected areas will be surveyed, graded, excavated and paved as necessary to clean and redirect the storm water runoff. The storm water runoff will be collected and discharged to existing water catch basins on site.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in depreciation and return is $486 or 4.8% lower than originally anticipated.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
All activities are complete.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $9,560.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Scherer Discharge Pipeline – Capital
Project No. 12

Project Description:
On March 16, 1992, pursuant to the provisions of the Georgia Water Quality control Act, as amended, the Federal Clean Water Act, as amended, and the rules and regulations promulgated thereunder, the Georgia Department of Natural Resources issued the National Pollutant Discharge Elimination System (NPDES) permit for Plant Scherer to Georgia Power Company. In addition to the permit, the Department issued Administrative Order EPD-WQ-1855 which provided a schedule for compliance by April 1, 1994 with new facility discharge limitations to Berry Creek. As a result of these new limitations, and pursuant to the order, Georgia Power Company was required to construct an alternate outfall to redirect certain wastewater discharges to the Ocmulgee River. Pursuant to the ownership agreement with Georgia Power Company for Scherer Unit 4, FPL is required to pay for its share of construction of the discharge pipeline which will constitute the alternate outfall.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in depreciation and return is $3,047 or 4.5% lower than projected.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
All activities are complete.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $62,796.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Disposal of Non-Contaminated Liquid Waste – Capital
Project No. 17b

Project Description:
FPL manages ash from heavy oil fired power plants using a wet ash system. Ash from the dust collector and economizer is sluiced to surface ash basins. The ash sludge is then pH adjusted to precipitate metals. In order to comply with Florida Administrative Code 62-701.300 (10), the ash is then de-watered using a plate/frame filter-press in order to dispose of it in a Class I landfill or ship by railcar to a processing facility for beneficial reuse.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
All activities are complete.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Wastewater Discharge Elimination & Reuse – Capital
Project No. 20

Project Description:
Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants and the Dade County DERM requires Turkey Point and Cutler Plant wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan Dade County.

In order to address these requirements, FPL has undertaken a multifaceted project which includes activities such as ash basin lining, installation of retention tanks, tank coating, sump construction, installation of pumps, motor, and piping, boiler blowdown recovery, site preparation, separation of stormwater and ashwater systems, separation of potable and service water systems, and the associated engineering and design work to implement these projects.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in depreciation and return is estimated to be $12,157 or 4.7% lower than originally anticipated.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
All activities are complete.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $240,966.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Turtle Net – 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.

The existing net is in need of maintenance. To facilitate this work, a temporary net will be situated to allow removal of the existing net. The new net having been properly coated for UV protection and anti-fouling will be installed replacing the existing net. The existing net will be repaired and maintained as a spare to allow rotation of the nets for future maintenance.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
FPL expects to purchase the new 5-inch net in the last quarter of 2007. The current net will be sent to the manufacturer for re-coating during the first quarter of 2008, at which time the new net will be installed.

Project Fiscal Expenditures:
(January 1, 2007 – December 31, 2007)
The variance in depreciation and return is estimated to be $4,865 or 5.0% lower than originally anticipated.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
The existing turtle net will be removed to be recoated and the new net will be installed in the interim. This net will serve as a backup net for future maintenance requirements.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $119,525.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pipeline Integrity Management (PIM) - Capital
Project No. 22

Project Description:
FPL is required to develop a written pipeline integrity management program for its hazardous liquid pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

Project Accomplishments: (January 1, 2007 to December 31, 2007)
No projects for 2007 cycle.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The leak detection system on the Martin 30" pipeline has been deferred until 2008, thus no expenditures were made in 2007.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
No projects for 2007 cycle.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $14,717.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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, 2007 to December 31, 2007)
The Facility Response Plans (FRP), which contain the SPCC plans, are scheduled to be issued by the end of the year. Additional required facility upgrades have been identified, and conceptual designs and cost estimates for the upgrades have been completed. The upgrades are scheduled to be completed in 2008.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
Estimated depreciation and return is 107,778 or 5.0% lower than projected. Previously planned diversionary structure work activities have been postponed, pending the completion of an assessment of existing diversionary structures. The Final Rule issued February 26, 2007 amending the existing SPCC Rule allows regulatory relief from containment requirements at facilities with oil-fired equipment by allowing an oil spill contingency planning option or active containment in addition to an inspection and monitoring program for oil-filled equipment in lieu of installing secondary containment or diversionary structures.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
The new containment structures are designed to contain 100% of the oil volume of the tanks, plus any potential fire deluge water. To account for rain water, the containments were equipment with sumps that can hold rainfall up to 2 inches. Once 2" of rain has accumulated, the sump is full and any additional water would impact the volume requirement of the spill containment. The plant is currently utilizing temporary, portable sump pumps to process the rain water. In heavy rain events, it is difficult to maintain the sumps and prevent overflow. Also, if there are any leaks in the turbine lube oil or diesel oil equipment, the oily water needs to be processed to remove the oil from the water before disposal.

In order to prevent heavy rainfall from impacting the required containment volume, permanent sump pumps and oil water separators need to be installed. On the St. Lucie Unit 1 Diesel Oil Storage Tank area, there is no local power source available and no oil/water separator. On Unit 1 and 2 Turbine Lube Oil areas, power is available from a nearby source and oil/water separators have been temporarily installed. The sump pumps and oil/water separators would be installed permanently in each area and procedures implemented to operation of the equipment. The project is scheduled to be completed in 2008.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $2,144,722.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Reburn – Capital
Project No. 24

Project Description:
This project involves installation of reburn technology in Manatee Units 1 and 2. Reburn is an advanced nitrogen oxides (NOx) control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers. The process is a proven advanced technology, with applications of a reburn-like flue gas incineration technique dating back to the late 1960s, and developments for applications to large coal fired power plants in the United States dating back to the early to mid 1980s.

Reburn is an in-furnace NOx control technology that employs fuel staging in a configuration where a portion of the fuel is injected downstream of the main combustion zone to create a second combustion zone, called the reburning zone. The reburning zone is operated under conditions where NOx from the main combustion zone is converted to elemental nitrogen (which makes up 79% of the atmosphere). The basic front wall-fired boiler reburning process is shown conceptually in Figure 1 (see below), and divides the furnace into three zones.

In the 1996-97 time period, FPL invested a considerable effort evaluating the Manatee Units for the application of reburn technology. FPL has recently reviewed the reburn system designs previously proposed for the Manatee units, and concluded that a design for either oil or gas reburn would require very similar characteristics. This will require reburn fuel injectors to be located at the elevation of the present top row of burners, with reburn injectors on the boiler front and rear walls. For the present application the injectors will be required to have a dual fuel (oil and gas) capability. In order to provide adequate residence time for the reburn process, it is proposed to locate the reburn overfire air (OFA) ports between the boiler wing walls and to angle them slightly to provide better mixing with the boiler flow. Because of the complexity of the boiler flow field and the port location, it was determined that OFA booster fans would be required to assist the air-fuel mixing and complete the burnout process. Installation of reburn technology for Manatee Units 1 and 2 offers the potential to reduce NOx emissions through a "pollution prevention" approach that does not require the use of reagents, catalysts, pollution reduction or removal equipment. FDEP and FPL agree that reburn technology is the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
Installation of the Unit 1 and Unit 2 equipment is complete, started up and completed process optimization of the new systems to ensure minimal emissions. Unit 1 is out of warranty. Unit 2 is still under warranty.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in depreciation and return is $132,521 or 2.6% lower than projected.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
Unit 1 and 2 both completed.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $5,024,450.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pt. Everglades ESP Technology – Capital
Project No. 25

Project Description:
The requirements of the Clean Air Act direct the EPA to develop health-based standards for certain "criteria pollutants". I.e. ozone (O_3), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM), nitrogen oxides (NOx), an lead (Pb). EPA developed standards for the criteria pollutants and regulates the emissions of those pollutants from major sources by way of the Title V permit program. Florida has been granted authority from the EPA to administer its own Title V program which is at least as stringent as the EPA requirements. Florida is able to, issue, renew and enforce Title V air operating permits for sources within the state via 403.061 Florida Statutes and Chapter 62-213 F.A.C., which is administered by the State of Florida Department of Environmental Protection ("DEP"). The Title V program addresses the six criteria pollutants mentioned earlier, and includes hazardous air pollutants (HAP). The EPA sets the limits of emissions of Hazardous Air Pollutants through the Maximum Achievable Control Technology (MACT). The original Port Everglades Title V permit, issued in 1998, expires on December 31, 2003 and must be renewed. The DEP's Final Title V permit for FPL Port Everglades plant requires FPL to install Electrostatic Precipitators at all four Port Everglades units to address local concerns and to insure compliance with the National Ambient Air Quality Stands and the EPA MACT Standards.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
During June, all major mechanical and electrical work was completed. All contractor punchlist items for the ESP were completed. Restoration of the plant property and grounds started during June. A Project Punchlist has been formalized with the plant and is being pursued.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
Estimated depreciation and return is $59,315 or 0.5% lower than projected. A combination of factors have led to the projected decrease in fiscal expenditures. Taking into account the supply of electricity, as compared to customer demand throughout the fleet, unit efficiency has usually demanded these units run less than anticipated. In addition, fuel economics to-date have also demanded the consumption of the least expensive fuel source, primarily natural gas, requiring less operation from the ESP's as initially predicted for 2007. This combination of unit efficiency and fuel economics has further lead to reduced equipment deterioration, with less generation of ash for disposal, requiring less overall maintenance activities.

Project Progress Summary:
(January 2007 - December 2007)
Construction on the Unit 3 electrostatic precipitator was completed in spring 2007 as the Unit went operational in May 2007. Therefore, at this time, all four ESP's (Units 1 through 4) have construction activities completed and are operational. The Units 1, 2 and 4 precipitators met all performance guarantees and permit requirements. Preliminary results of Unit 3 performance test exceeded all performance guarantees. The Unit 1, 2 and 4 stack emissions were well below the new Title V permit requirements of .03 lb/mmbtu particulate and 20% opacity. Enclosure of ash truck loading bay is planned to contain fugitive airborne ash during truck loadings. The Ash Enclosure design, material and erection contract will be turned over to the plant for implementation (scheduled for Fall 2007).

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $11,903,263.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: UST Replacement/Removal – Capital
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 Category-A tanks are single-walled tanks or underground single-walled piping with no secondary containment that was installed before June 30, 1992.

UST Category-B tanks are 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 and AST Category-C tanks under F.A.C. 62-761.500 are tanks that shall have some or all of the following; a double wall, be made of fiberglass, have exterior coatings that protect the tank from external corrosion, secondary containment (e.g., concrete walls and floor) for the tank and the piping, and overfill protection.

FPL has six Category-A and two Category-B Storage Tank Systems that must be removed or replaced in order to meet the performance standards of Rule 61-761.500. In 2004 FPL will replace the two single-walled USTs located at the Turkey Point Nuclear Plant Units 1 and 2 with ASTs providing secondary containment (concrete walls and floor) surrounding the tanks. Also in 2004, FPL will remove one single-walled UST located at the Ft. Lauderdale Plant and will not replace the tank. In 2005-2006 FPL will replace the single-walled USTs located at the Area Office Broward (one UST in 2005), Customer Service East Office (one UST in 2006), Juno Beach Office (one UST in 2005), and General Office (2 USTs in 2005), with double-walled tanks providing electronic leak detection. Additionally, the AST to be installed at the Area Broward Office will be concrete vaulted.

The removal and replacement of the USTs will be performed by outside contractors. Additionally, closure assessments will be performed in accordance with 62-761.800 and closure assessment reports will be submitted to local Counties, and the Department of Environmental Services (DEP).

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
There were no activities in 2007.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
Depreciation and return is estimated to be $0.

Project Progress Summary:
(January 2007 - December 2007)
Initial review of the scope of work has been completed.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 are expected to be $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: CAIR Compliance – Capital
Project No. 31

Project Description:
The CAIR Project was initiated to implement strategies to comply with CAIR Annual and Ozone Season NOx emissions requirements. The CAIR project to date has included the Black & Veatch (B&V) study of FPL's control and allowance management options, an engineering study conducted by Aptech for the reliable cycling of the 800 MW units, and a review of CEMS monitoring changes required for the peaking gas turbine units. The 800 MW Cycling Project was added to CAIR after 2006 submittal. Aptech Engineering provided engineering services for the first phase of a multiphase scope of work that will assure that the operating reliability is maintained in the new operating mode. FPL anticipates changing the operating mode of its four 800 MW units at Martin and Manatee Plants. The "study cost" so far to Aptech Engineering have been paid. They have identified several countermeasures that are being prioritized and scheduled for implementation in 2008 – 2011. The update to the Gas Turbine Peaking Unit CEMS requirements identified the need to implement a revised CEMS monitoring program for those units which will now require CEMS under the CAIR program requirements. FPL has determined that the implementation of the Low Mass Emissions option under 40 CFR Part 75 as the preferred option. The CEMS installations will require emissions testing of representative units and the procurement and installation of a Continuous Emissions Monitor at the Port Everglades GTs, Lauderdale GTs and Fort Myers GTs.

Project Accomplishments:
(January. 1, 2007 to July 1, 2007)
- Completed B & V study of CAIR compliance options
- Completed 800 MW Cycling Engineering Study

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in depreciation and return is $2,742,160 or 63.9% lower than projected.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
Evaluation of CAIR compliance options identified the 800 MW cycling project as most cost effective control option identified for compliance with CAIR. Project scope, outage planning and activities have been identified for implementation at the Martin and Manatee 800 MW units. The GT CEMS project has identified the hardware components which will be required and modifications which must be made to emission stacks of the representative units at each GT site.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December 2008 is $5,905,506.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: CAMR Compliance – Capital
Project No. 33

Project Description:
The Clean Air Mercury Rule (CAMR) was promulgated by the Environmental Protection Agency (EPA) on March 15, 2005, imposing nation-wide standards of performance for mercury (Hg) emissions from existing and new coal-fired electric utility steam generating units. The CAMR is designed to reduce emissions of Hg through implementation of coal-fired generating unit Hg controls. In addition, CAMR requires the installation of Hg Continuous Emission Monitoring Systems (HgCEMS) to monitor compliance with the emission requirements. The rule is implemented in two phases with an initial compliance date of 2010 for Phase I and the final required reductions of Phase II in 2018. The State of Florida has begun the implementation of the requirements for reduction of Hg through rule making process. Plant St. John's River Power Park (SJRPP) Units 1 & 2, in which FPL has 20% ownership shares, are affected units under this rule and will require the installation of Hg controls and HgCEMS. Similarly the State of Georgia has also begun their rule making process to implement the federal rule which will affect FPL's ownership share of Plant Scherer Unit 4 also requiring the installation of HgCEMS and Hg controls.

Project Accomplishments:
(January 1, 2007 to December 31, 2007)
FPL completed the evaluation of mercury control options for Plant Scherer and approved the co-owner plan to proceed with the installation of a baghouse/sorbant-injection system on its ownership share of Plant Scherer. In June 2007 FPL issued a limited notice to proceed to the controls contractor BE&K.

Project Fiscal Expenditures:
(January 1, 2007 to December 31, 2007)
The variance in depreciation and return is $1,254,563 or 78.7% lower than projected. Engineering and procurement activities associated with Scherer, which were projected for 2007, will now be performed in 2008.

Project Progress Summary:
(January 1, 2007 to December 31, 2007)
The FPL CAMR project at Plant Scherer includes FPL's costs from the installation of a Baghouse, a mercury sorbant injection system with associated controls and material handling equipment, and capital additions to Plant Scherer common areas to accommodate sorbant delivery and storage and spent sorbant disposal. Mercury controls at Plant Scherer are being installed on all 4 units at the plant to comply with the CAMR. Installation of controls requires a specific sequence for the construction of the controls and material handling systems. To date engineering and design work for the baghouses and sorbant handling equipment was initiated in April of 2007 with design work completed in 2008. Unit 3 at the plant has begun preliminary construction work for installation of the baghouse and common plant material handling equipment. Installation of the mercury monitor is projected to be completed by December 2008 with the baghouse on Unit 4 is projected to be completed in early 2010.

Project Projections:
(January 1, 2008 - December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for the period January 2008 through December are projected to be $4,094,304.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Cooling Water System Inspection and Maintenance – Capital
Project No. 34

Project Description:
The purpose of the proposed St. Lucie Plant Cooling Water System Inspection and Maintenance Project (the "Project") is to inspect and, as necessary, maintain the cooling water system at FPL's St. Lucie nuclear plant (the "Cooling System") such that it minimizes injuries and/or deaths of endangered species and thus helps FPL to remain in compliance with the federal Endangered Species Act, 16 U.S.C. Section 1531, et seq. (the "ESA") The St. Lucie Plant is an electric generating station on Hutchinson Island in St. Lucie County, Florida. The plant consists of two nuclear-fueled 850 net MWe units, both of which use the Atlantic Ocean as a source of water for once-through condenser cooling. This cooling water is supplied to the units via the Cooling System. The St. Lucie Plant cannot operate without the Cooling System. Compliance with the ESA is a condition to the operation of the St. Lucie Plant. Inspection and cleaning of the intake pipes is an "environmental compliance cost" under section 366.8255, Florida Statutes. The specific "environmental law or regulation" requiring inspection and cleaning of the intake pipes are terms and conditions that will be imposed pursuant to a Biological Opinion ("BO") that is to be issued by the National Oceanic and Atmospheric Administration ("NOAA") pursuant to section 7 of the ESA. NOAA will finalize the BO in 2007. NOAA sent the Nuclear Regulatory Commission ("NRC") a letter dated December 19, 2006, confirming its intent to issue the BO and stating the requirements that will be imposed pursuant to the BO with respect to inspection and cleaning of the intake pipes.

Project Accomplishments:
(January 8, 2007 thru December 31, 2007)
Inspections have been completed on all intake and discharge lines. Currently we are reviewing bids for the cleaning of the intake lines for SL2 fall 2007. We expect the cleaning to be completed prior to the end of the year. Should the cleaning not be completed in 2007 we will be continuing in the SL1 outage.

Project Fiscal Expenditures:
(January 8, 2007 to December 31, 2007)
Per FPL's petition filed on January 8, 2007, depreciation and return are estimated to be $0.

Project Progress Summary:
(January 8, 2007 to December 31, 2007)
The inspections of the ocean intakes and discharges were completed during the SL1 Spring 2007 outage in April and May. Cleaning of select areas of the three ocean intake pipes and velocity caps is scheduled for the SL2 outage planned for the Fall 2007, October 1- Dec 25.

Project Projections:
(January 1, 2008 to December 31, 2008)
Estimated project fiscal expenditures (depreciation and return) for January 2008 through December 2008 are expected to be $14,504.

Form 42-6P

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % By Rate Class
January 2008 to December 2008

Rate Class	(1) Avg 12 CP Load Factor at Meter (%)	(2) GCP Load Factor at Meter (%)	(3) Projected Sales at Meter (KWH)	(4) Projected Avg 12 CP at Meter (KW)	(5) Projected GCP at Meter (KW)	(6) Demand Loss Expansion Factor	(7) Energy Loss Expansion Factor	(8) Projected Sales at Generation (KWH)	(9) Projected Avg 12 CP at Generation (kW)	(10) Projected GCP Demand at Generation (kW)	(11) Percentage of KWH Sales at Generation (%)	(12) Percentage of 12 CP Demand at Generation (%)	(13) Percentage of GCP Demand at Generation (%)
RS1/RST1	64.061%	58.728%	58,804,147,081	10,478,766	11,430,270	1.09370109	1.07349429	63,125,916,120	11,460,638	12,501,299	52.68401%	57.06444%	55.75281%
GS1/GST1	65.694%	55.328%	6,619,341,251	1,150,231	1,365,725	1.09370109	1.07349429	7,105,825,036	1,258,009	1,493,695	5.93042%	6.26384%	6.66152%
GSD1/GSDT1/HLTF(21-499 kW)	74.508%	66.100%	25,774,860,665	3,949,020	4,451,320	1.09361402	1.07343073	27,667,527,500	4,318,704	4,868,026	23.09093%	21.50355%	21.71024%
OS2	57.663%	20.058%	19,993,143	3,958	11,379	1.05919630	1.04702619	20,933,344	4,192	12,053	0.01747%	0.02087%	0.05375%
GSLD1/GSLDT1/CS1/CST1/HLTF(500-1,999 kW)	77.165%	68.463%	11,789,652,172	1,744,121	1,965,809	1.09222289	1.07237880	12,642,973,049	1,904,969	2,147,102	10.55165%	9.48516%	9.57556%
GSLD2/GSLDT2/CS2/CST2/HLTF(2,000+ kW)	90.280%	79.460%	2,169,713,444	274,351	311,709	1.08471538	1.06646905	2,313,932,235	297,593	338,116	1.93118%	1.48177%	1.50792%
GSLD3/GSLDT3/CS3/CST3	89.044%	68.816%	258,589,835	33,151	42,896	1.03077723	1.02508821	265,077,391	34,171	44,216	0.22123%	0.17014%	0.19719%
ISST1D	84.918%	63.966%	0	0	0	1.05919630	1.04702619	0	0	0	0.00000%	0.00000%	0.00000%
ISST1T	131.296%	38.558%	0	0	0	1.03077723	1.02508821	0	0	0	0.00000%	0.00000%	0.00000%
SST1T	131.296%	38.558%	162,838,087	14,158	48,210	1.03077723	1.02508821	166,923,403	14,594	49,694	0.13931%	0.07267%	0.22162%
SST1D1/SST1D2/SST1D3	84.918%	63.966%	8,479,038	1,140	1,513	1.05919630	1.04702619	8,877,775	1,207	1,603	0.00741%	0.00601%	0.00715%
CILC D/CILC G	89.894%	84.914%	3,701,861,702	470,095	497,665	1.08178491	1.06440541	3,940,281,623	508,542	538,366	3.28850%	2.53212%	2.40098%
CILC T	90.295%	80.118%	1,676,506,768	211,952	238,874	1.03077723	1.02508821	1,718,567,321	218,475	246,226	1.43429%	1.08782%	1.09811%
MET	66.435%	58.382%	101,103,804	17,373	19,769	1.05919630	1.04702619	105,858,331	18,401	20,939	0.08835%	0.09162%	0.09338%
OL1/SL1/PL1	210.146%	49.089%	601,242,889	32,661	139,817	1.09370109	1.07349429	645,430,808	35,721	152,918	0.53867%	0.17786%	0.68198%
SL2, GSCU1	126.155%	125.997%	85,476,122	7,735	7,744	1.09370109	1.07349429	91,758,129	8,460	8,470	0.07658%	0.04212%	0.03777%
TOTAL			111,773,806,000	18,388,712	20,532,700			119,819,882,065	20,083,676	22,422,723	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 2008 through December 2008
(4) Calculated: (Col 3)/(8,760 * Col 1)
(5) Calculated: (Col 3)/8,760 * Col 2)
(6) Based on 2006 demand losses
(7) Based on 2006 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

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of Environmental Cost Recovery Clause Factors
January 2008 to December 2008

Rate Class	(1) Percentage of KWH Sales at Generation (%)	(2) Percentage of 12 CP Demand at Generation (%)	(3) Percentage of GCP Demand at Generation (%)	(4) Energy Related Cost ($)	(5) CP Demand Related Cost ($)	(6) GCP Demand Related Cost ($)	(7) Total Environmental Costs ($)	(8) Projected Sales at Meter (KWH)	(9) Environmental Cost Recovery Factor ($/KWH)
RS1/RST1	52.68401%	57.06444%	55.75281%	$14,033,197	$9,396,913	$369,023	$23,799,133	58,804,147,081	0.00040
GS1/GST1	5.93042%	6.26384%	6.66152%	$1,579,659	$1,031,478	$44,092	$2,655,229	6,619,341,251	0.00040
GSD1/GSDT1/HLTF(21-499 kW)	23.09093%	21.50355%	21.71024%	$6,150,625	$3,541,032	$143,698	$9,835,355	25,774,860,665	0.00038
OS2	0.01747%	0.02087%	0.05375%	$4,654	$3,437	$356	$8,447	19,993,143	0.00042
GSLD1/GSLDT1/CS1/CST1/HLTF(500-1,999 kW)	10.55165%	9.48516%	9.57556%	$2,810,594	$1,561,940	$63,380	$4,435,914	11,789,652,172	0.00038
GSLD2/GSLDT2/CS2/CST2/HLTF(2,000+ kW)	1.93118%	1.48177%	1.50792%	$514,398	$244,005	$9,981	$768,384	2,169,713,444	0.00035
GSLD3/GSLDT3/CS3/CST3	0.22123%	0.17014%	0.19719%	$58,928	$28,018	$1,305	$88,251	258,589,835	0.00034
ISST1D	0.00000%	0.00000%	0.00000%	$0	$0	$0	$0	0	0.00036
ISST1T	0.00000%	0.00000%	0.00000%	$0	$0	$0	$0	0	0.00031
SST1T	0.13931%	0.07267%	0.22162%	$37,108	$11,966	$1,467	$50,541	162,838,087	0.00031
SST1D1/SST1D2/SST1D3	0.00741%	0.00601%	0.00715%	$1,974	$990	$47	$3,011	8,479,038	0.00036
CILC D/CILC G	3.28850%	2.53212%	2.40098%	$875,944	$416,968	$15,892	$1,308,804	3,701,861,702	0.00035
CILC T	1.43429%	1.08782%	1.09811%	$382,046	$179,134	$7,268	$568,448	1,676,506,768	0.00034
MET	0.08835%	0.09162%	0.09338%	$23,533	$15,088	$618	$39,239	101,103,804	0.00039
OL1/SL1/PL1	0.53867%	0.17786%	0.68198%	$143,462	$29,289	$4,514	$177,285	601,242,889	0.00029
SL2, GSCU1	0.07658%	0.04212%	0.03777%	$20,398	$6,937	$250	$27,585	85,476,122	0.00032
TOTAL				$26,636,540	$16,467,194	$661,892	$43,765,627	111,773,806,000	0.00039

Note: There are currently no customers taking service on Schedules ISST1(D) or ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 Factor.

(1) From Form 42-6P, Col 11
(2) From Form 42-6P, Col 12
(3) From Form 42-6P, Col 13
(4) Total Energy $ from Form 42-1P, Line 5b x Col 1
(5) Total CP Demand $ from Form 42-1P, Line 5b x Col 2
(6) Total GCP Demand $ from Form 42-1P, Line 5b x Col 3
(7) Col 4 + Col 5 + Col 6
(8) Projected KWH sales for the period January 2008 through December 2008
(9) Col 7 / Col 8 x 100

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Form 42-1E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up
for the Period January through December 2007

Line No.		
1	Over/(Under) Recovery for the Current Period (Form 42-2E, Page 2 of 2, Line 5)	($1,186,248)
2	Interest Provision (Form 42-2E, Page 2 of 2, Line 6)	$600,422
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 2008	($585,826)

( ) Reflects Underrecovery

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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2007

Form 42-2E
Page 1 of 2

Line No.		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June
1	ECRC Revenues (net of Revenue Taxes)	$1,983,736	$1,707,980	$1,689,491	$1,713,020	$1,891,211	$2,088,038
2	True-up Provision (Order No. PSC-06-0972-FOF-EI)	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,321,456	3,045,700	3,027,211	3,050,739	3,228,931	3,425,758
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5E, Line 9)	566,436	598,119	1,725,067	1,037,492	621,715	1,666,686
	b - Capital Investment Projects (Form 42-7E, Line 9)	1,629,758	1,759,288	1,787,917	1,809,768	1,850,913	1,953,773
	c - Total Jurisdictional ECRC Costs	2,196,194	2,357,407	3,512,984	2,847,260	2,472,628	3,620,459
5	Over/(Under) Recovery (Line 3 - Line 4c)	1,125,262	688,293	(485,773)	203,479	756,303	(194,701)
6	Interest Provision (Form 42-3E, Line 10)	76,826	75,201	70,111	63,936	60,456	56,195
7	Prior Periods True-Up to be (Collected)/Refunded in 2007	16,052,637	15,917,005	15,342,779	13,589,397	12,519,093	11,998,132
	a - Deferred True-Up from 2006 (Form 42-1A, Line 7)	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849
8	True-Up Collected /(Refunded) (See Line 2)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)
9	End of Period True-Up (Lines 5+6+7+7a+8)	17,480,854	16,906,628	15,153,246	14,082,942	13,561,981	12,085,755
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$17,480,854	$16,906,628	$15,153,246	$14,082,942	$13,561,981	$12,085,755

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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2007

Form 42-2E
Page 2 of 2

Line No.		Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$2,360,856	$2,374,903	$2,360,601	$2,216,793	$1,979,023	$1,994,994	$24,360,645
2	True-up Provision (Order No. PSC-06-0972-FOF-EI)	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720	16,052,637
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,698,576	3,712,622	3,698,320	3,554,512	3,316,742	3,332,713	40,413,282
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5E, Line 9)	1,435,857	1,427,308	1,966,801	2,431,111	2,162,843	2,290,581	17,930,015
	b - Capital Investment Projects (Form 42-7E, Line 9)	2,048,828	2,090,275	2,134,090	2,172,788	2,200,735	2,231,382	23,669,515
	c - Total Jurisdictional ECRC Costs	3,484,685	3,517,583	4,100,891	4,603,899	4,363,578	4,521,963	41,599,530
5	Over/(Under) Recovery (Line 3 - Line 4c)	213,891	195,039	(402,571)	(1,049,387)	(1,046,836)	(1,189,250)	(1,186,248)
6	Interest Provision (Form 42-3E, Line 10)	50,705	45,942	39,801	30,896	20,534	9,819	600,422
7	Prior Periods True-Up to be (Collected)/Refunded in 2007	10,521,906	9,448,782	8,352,044	6,651,555	4,295,345	1,931,324	16,052,637
	a - Deferred True-Up from 2006 (Form 42-1A, Line 7)	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849
8	True-Up Collected /(Refunded) (See Line 2)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(16,052,637)
9	End of Period True-Up (Lines 5+6+7+7a+8)	11,012,631	9,915,893	8,215,404	5,859,194	3,495,173	978,023	978,023
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	$11,012,631	$9,915,893	$8,215,404	$5,859,194	$3,495,173	$978,023	$978,023

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2007

Form 42-3E
Page 1 of 2

Interest Provision (in Dollars)

Line No.		January	February	March	April	May	June
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$17,616,486	$17,480,854	$16,906,628	$15,153,246	$14,082,942	$13,561,981
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	17,404,028	16,831,427	15,083,135	14,019,006	13,501,525	12,029,560
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$35,020,514	$34,312,281	$31,989,763	$29,172,252	$27,584,467	$25,591,541
4	Average True-Up Amount (Line 3 x 1/2)	$17,510,257	$17,156,141	$15,994,882	$14,586,126	$13,792,234	$12,795,771
5	Interest Rate (First Day of Reporting Month)	5.27000%	5.26000%	5.26000%	5.26000%	5.26000%	5.26000%
6	Interest Rate (First Day of Subsequent Month)	5.26000%	5.26000%	5.26000%	5.26000%	5.26000%	5.28000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.53000%	10.52000%	10.52000%	10.52000%	10.52000%	10.54000%
8	Average Interest Rate (Line 7 x 1/2)	5.26500%	5.26000%	5.26000%	5.26000%	5.26000%	5.27000%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.43875%	0.43833%	0.43833%	0.43833%	0.43833%	0.43917%
10	Interest Provision for the Month (Line 4 x Line 9)	$76,826	$75,201	$70,111	$63,936	$60,456	$56,195

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2007

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)	$12,085,755	$11,012,631	$9,915,893	$8,215,404	$5,859,194	$3,495,173	$145,386,187
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	10,961,926	9,869,951	8,175,603	5,828,298	3,474,639	968,204	128,147,302
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$23,047,681	$20,882,582	$18,091,496	$14,043,702	$9,333,833	$4,463,377	$273,533,489
4	Average True-Up Amount (Line 3 x 1/2)	$11,523,841	$10,441,291	$9,045,748	$7,021,851	$4,666,917	$2,231,689	$136,766,745
5	Interest Rate (First Day of Reporting Month)	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	N/A
6	Interest Rate (First Day of Subsequent Month)	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.56000%	10.56000%	10.56000%	10.56000%	10.56000%	10.56000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.44000%	0.44000%	0.44000%	0.44000%	0.44000%	0.44000%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$50,705	$45,942	$39,801	$30,896	$20,534	$9,819	$600,422

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
January 2007 - December 2007

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	$ 908,197	$ 931,745	$ (23,548)	-2.5%
3b	Continuous Emission Monitoring Systems-Capital	1,025,600	1,085,789	(60,189)	-5.5%
4b	Clean Closure Equivalency-Capital	3,990	4,148	(158)	-3.8%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	1,758,715	1,832,742	(74,027)	-4.0%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	1,600	1,674	(74)	-4.4%
8b	Oil Spill Cleanup/Response Equipment-Capital	73,475	71,718	1,757	2.4%
10	Relocate Storm Water Runoff-Capital	9,743	10,229	(486)	-4.8%
NA	SO2 Allowances-Negative Return on Investment	(284,008)	(254,313)	(29,695)	11.7%
12	Scherer Discharge Pipeline-Capital	64,314	67,361	(3,047)	-4.5%
17b	Disposal of Noncontainerized Liquid Wate-Capital	0	0	0	0.0%
20	Wastewater Discharge Elimination & Reuse	245,826	257,983	(12,157)	-4.7%
21	St. Lucie Turtle Net	92,461	97,326	(4,865)	-5.0%
22	Pipeline Integrity Management	0	0	0	0.0%
23	SPCC-Spill Prevention, Control & Countermeasures	2,036,766	2,144,544	(107,778)	-5.0%
24	Manatee Reburn	4,886,546	5,019,067	(132,521)	-2.6%
25	Pt. Everglades ESP Technology	11,288,005	11,347,320	(59,315)	-0.5%
26	UST Replacement/Removal	-	67,554	(67,554)	-100.0%
31	CAIR Compliance	1,551,150	4,293,310	(2,742,160)	-63.9%
33	CAMR Compliance	340,077	1,594,640	(1,254,563)	-78.7%
35	Martin Plant Drinking Water System Compliance	0	0	0	100.0%
2	Total Investment Projects-Recoverable Costs	$ 24,002,457	$ 28,572,837	$ (4,570,380)	-16.0%
3	Recoverable Costs Allocated to Energy	$ 18,299,579	$ 18,932,935	$ (633,356)	-3.3%
4	Recoverable Costs Allocated to Demand	$ 5,702,878	$ 9,639,902	$ (3,937,024)	-40.8%

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-06-0972-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

REVISED 8/31/07

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/actual True-up Amount for the Period
January 2007 - December 2007

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	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	78,002	77,587	77,172	76,730	76,289	75,874	461,654
3b	Continuous Emission Monitoring Systems-Capital	86,718	86,399	86,110	85,787	85,483	85,248	515,745
4b	Clean Closure Equivalency-Capital	338	337	336	335	334	333	2,013
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	148,800	148,393	147,985	147,578	147,171	146,763	886,690
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	135	135	134	134	134	133	805
8b	Oil Spill Cleanup/Response Equipment-Capital	6,035	5,997	5,961	5,926	5,940	5,947	35,806
10	Relocate Storm Water Runoff-Capital	819	818	816	815	814	813	4,895
NA	SO2 Allowances-Negative Return on Investment	-19,422	-19,315	-19,208	-24,146	-27,815	-26,769	-136,675
12	Scherer Discharge Pipeline-Capital	5,417	5,407	5,396	5,386	5,375	5,365	32,346
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	20,671	20,637	20,604	20,570	20,536	20,502	123,520
21	St. Lucie Turtle Net	7,754	7,745	7,736	7,727	7,718	7,710	46,390
22	Pipeline Integrity Management	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	163,718	166,878	168,591	168,533	170,666	172,206	1,010,592
24	Manatee Rebum	382,830	381,974	381,117	380,166	379,142	405,708	2,310,937
25	Pt. Everglades ESP Technology	732,367	848,999	868,422	887,706	913,016	962,744	5,213,254
26	UST Removal / Replacement	0	0	0	0	0	0	0
31	CAIR Compliance	33,991	46,084	55,584	64,479	83,186	103,675	386,999
33	CAMR Compliance	4,539	6,005	6,353	7,537	8,988	15,031	48,453
35	Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$ 1,652,712	$ 1,784,080	$ 1,813,109	$ 1,835,263	$ 1,876,977	$ 1,981,283	$ 10,943,424
3	Recoverable Costs Allocated to Energy	$ 1,290,666	$ 1,407,062	$ 1,425,882	$ 1,439,245	$ 1,460,797	$ 1,539,611	$ 8,563,262
4	Recoverable Costs Allocated to Demand	$ 362,046	$ 377,018	$ 387,227	$ 396,018	$ 416,180	$ 441,672	$ 2,380,162
5	Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	
6	Retail Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,272,471	$ 1,387,227	$ 1,405,781	$ 1,418,956	$ 1,440,204	$ 1,517,907	$ 8,442,546
8	Jurisdictional Demand Recoverable Costs (C)	$ 357,287	$ 372,061	$ 382,136	$ 390,812	$ 410,709	$ 435,866	$ 2,348,871
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 1,629,758	$ 1,759,288	$ 1,787,917	$ 1,809,768	$ 1,850,913	$ 1,953,773	$ 10,791,417

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

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/actual True-up Amount for the Period
January 2007 - December 2007

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	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	75,460	75,045	74,631	74,217	73,802	73,388	446,543	908,197		908,197
3b	Continuous Emission Monitoring Systems-Capital	85,204	85,118	84,841	84,717	84,963	85,012	509,855	1,025,600		1,025,600
4b	Clean Closure Equivalency-Capital	332	331	330	329	328	327	1,977	3,990	3,683	307
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	146,356	145,949	145,541	145,134	144,726	144,319	872,025	1,758,715	1,623,429	135,286
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	133	133	133	132	132	132	795	1,600	1,477	123
8b	Oil Spill Cleanup/Response Equipment-Capital	6,168	6,307	6,270	6,233	6,195	6,496	37,669	73,475	67,823	5,652
10	Relocate Storm Water Runoff-Capital	811	810	809	807	806	805	4,848	9,743	8,994	749
NA	SO2 Allowances-Negative Return on Investment	-26,632	-25,801	-24,971	-24,140	-23,310	-22,479	-147,333	-284,008		-284,008
12	Scherer Discharge Pipeline-Capital	5,354	5,344	5,333	5,323	5,312	5,302	31,968	64,314	59,367	4,947
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	20,469	20,435	20,401	20,367	20,334	20,300	122,306	245,826	226,916	18,910
21	St. Lucie Turtle Net	7,701	7,692	7,683	7,674	7,665	7,656	46,071	92,461	85,349	7,112
22	Pipeline Integrity Management	0	0	0	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	171,987	171,604	171,221	170,837	170,454	170,071	1,026,174	2,036,766	1,880,092	156,674
24	Manatee Reburn	432,203	431,029	429,855	428,681	427,507	426,334	2,575,609	4,886,546		4,886,546
25	Pt. Everglades ESP Technology	1,004,688	1,014,292	1,016,555	1,015,791	1,013,125	1,010,300	6,074,751	11,288,005		11,288,005
26	UST Removal / Replacement	0	0	0	0	0	0	0	0	0	0
31	CAIR Compliance	125,719	154,151	185,167	211,672	231,400	256,042	1,164,151	1,551,150	1,431,831	119,319
33	CAMR Compliance	21,719	27,243	40,287	55,526	68,180	78,669	291,624	340,077	313,917	26,160
35	Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$ 2,077,672	$ 2,119,682	$ 2,164,086	$ 2,203,300	$ 2,231,619	$ 2,262,674	$ 13,059,033	$ 24,002,457	$ 5,702,878	$ 18,299,579
3	Recoverable Costs Allocated to Energy	$ 1,609,904	$ 1,621,221	$ 1,625,771	$ 1,627,269	$ 1,626,513	$ 1,625,641	$ 9,736,318	$ 18,299,579		
4	Recoverable Costs Allocated to Demand	$ 467,768	$ 498,461	$ 538,315	$ 576,031	$ 605,106	$ 637,033	$ 3,322,715	$ 5,702,878		
5	Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%				
6	Retail Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%				
7	Jurisdictional Energy Recoverable Costs (B)	$ 1,587,209	$ 1,598,367	$ 1,602,852	$ 1,604,329	$ 1,603,584	$ 1,602,724	$ 9,599,065	$ 18,041,611		
8	Jurisdictional Demand Recoverable Costs (C)	$ 461,619	$ 491,908	$ 531,238	$ 568,459	$ 597,151	$ 628,658	$ 3,279,033	$ 5,627,904		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 2,048,828	$ 2,090,275	$ 2,134,090	$ 2,172,788	$ 2,200,735	$ 2,231,382	$ 12,878,098	$ 23,669,515		

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

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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	(2,105,917)	(2,094,333)	(2,082,750)	(2,071,166)	(3,150,774)	(2,864,494)	(2,924,623)		
2	Total Working Capital	($2,105,917)	($2,094,333)	($2,082,750)	($2,071,166)	($3,150,774)	($2,864,494)	($2,924,623)		
3	Average Net Working Capital Balance		(2,100,125)	(2,088,542)	(2,076,958)	(2,610,970)	(3,007,634)	(2,894,558)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(16,138)	(16,049)	(15,960)	(20,063)	(23,111)	(22,242)	(113,563)	
	b Debt Component (Line 6 x 1.87670% x 1/12)		(3,284)	(3,266)	(3,248)	(4,083)	(4,704)	(4,527)	(23,113)	
5	Total Return Component		($19,422)	($19,315)	($19,208)	($24,146)	($27,815)	($26,769)	($136,675)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(11,584)	(11,584)	(11,584)	(11,584)	(328,710)	(89,804)	(464,848)	
	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)		($11,584)	($11,584)	($11,584)	($11,584)	($328,710)	($89,804)	($464,848)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(31,006)	(30,899)	(30,791)	(35,730)	(356,525)	(116,573)		
	a Recoverable Costs Allocated to Energy		(31,006)	(30,899)	(30,791)	(35,730)	(356,525)	(116,573)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%		
10	Demand Jurisdictional Factor		98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%		
11	Retail Energy-Related Recoverable Costs (B)		(30,551)	(30,445)	(30,340)	(35,206)	(351,296)	(114,863)	(592,702)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($30,551)	($30,445)	($30,340)	($35,206)	($351,296)	($114,863)	($592,702)	

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 5.6640% reflects an 11.75% 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 2007

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	(2,924,623)	(2,834,819)	(2,745,016)	(2,655,212)	(2,565,408)	(2,475,604)	(2,385,801)		
2	Total Working Capital	($2,924,623)	($2,834,819)	($2,745,016)	($2,655,212)	($2,565,408)	($2,475,604)	($2,385,801)		
3	Average Net Working Capital Balance		(2,879,721)	(2,789,917)	(2,700,114)	(2,610,310)	(2,520,506)	(2,430,702)		
4	Return on Average Net Working Capital Balance									
	a Equity Component grossed up for taxes (A)		(22,128)	(21,438)	(20,748)	(20,058)	(19,368)	(18,678)	(235,981)	
	b Debt Component (Line 6 x 1.87670% x 1/12)		(4,504)	(4,363)	(4,223)	(4,082)	(3,942)	(3,801)	(48,028)	
5	Total Return Component		($26,632)	($25,801)	($24,971)	($24,140)	($23,310)	($22,479)	($284,009)	(D)
6	Expense Dr (Cr)									
	a 411.800 Gains from Dispositions of Allowances		(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(1,003,670)	
	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)		($89,804)	($89,804)	($89,804)	($89,804)	($89,804)	($89,804)	($1,003,670)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		($116,436)	($115,605)	($114,775)	($113,944)	($113,114)	($112,283)		
	a Recoverable Costs Allocated to Energy		(116,436)	(115,605)	(114,775)	(113,944)	(113,114)	(112,283)		
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%		
10	Demand Jurisdictional Factor		98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%		
11	Retail Energy-Related Recoverable Costs (B)		(114,728)	(113,910)	(113,091)	(112,273)	(111,455)	(110,636)	(1,268,796)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($114,728)	($113,910)	($113,091)	($112,273)	($111,455)	($110,636)	($1,268,796)	

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 5.6640% reflects an 11.75% 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

Department of Environmental Protection
Drinking Water Standards, Monitoring, and Reporting

Rule 62-550.310, F.A.C.
Primary Drinking Water Standards: Maximum Contaminant Levels and Maximum Residual Disinfectant Levels

RRL-1
DOCKET NO. 070007-EI
FPL WITNESS: R.R. LABAUVE
EXHIBIT _____
PAGES 1-3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 7
COMPANY Florida Power + Light
WITNESS R. R. LaBauve (RRL-1)
DATE 11-06-07

62-550.310 Primary Drinking Water Standards: Maximum Contaminant Levels and Maximum Residual Disinfectant Levels.

(These standards may also apply as ground water quality standards as referenced in Chapter 62-520, F.A.C.)

(1) INORGANICS – Except for nitrate and nitrite, which apply to all public water systems, this subsection applies to community water systems and non-transient non-community water systems only.

(a) The maximum contaminant levels for the inorganic contaminants are listed in Table 1, which is incorporated herein and appears at the end of this chapter.

(b) The maximum contaminant level for nitrate (as N) applicable to transient non-community water systems is 10 milligrams per liter. The Department or Approved County Health Department shall allow a contaminant level for nitrate (as N) of up to 20 milligrams per liter upon a showing by the supplier of water that the following conditions are met:

1. The water distributed by the water system is not available to children under 6 months of age or to lactating mothers, and

2. There is continuous public notification of what the nitrate level (as N) is and what the potential health effects of such exposure are.

3. The Department shall require monitoring every 3 months as long as the maximum contaminant level is exceeded. Should adverse health effects occur, the Department shall require immediate compliance with the maximum contaminant level for nitrate (as N).

(c) The revised maximum contaminant level of 0.010 mg/L for arsenic becomes effective January 1, 2005. All community and non-transient non-community water systems shall demonstrate compliance with the revised maximum contaminant level by December 31, 2007.

(2) DISINFECTANT RESIDUALS – Except for the chlorine dioxide maximum residual disinfectant level, which applies to all public water systems using chlorine dioxide as a disinfectant or oxidant, this subsection applies only to community or non-transient non-community water systems adding a chemical disinfectant to the water in any part of the drinking water treatment process. Maximum residual disinfectant levels (MRDLs) are listed in Table 2, which is incorporated herein and appears at the end of this chapter.

(3) DISINFECTION BYPRODUCTS – This subsection applies to all community or non-transient non-community water systems adding a chemical disinfectant to the water in any part of the drinking water treatment process. The Stage 1 maximum contaminant levels (MCLs) for disinfection byproducts are listed in Table 3, which is incorporated herein and appears at the end of this chapter.

(4) ORGANICS – This subsection applies only to community water systems and non-transient non-community water systems.

(a) The maximum contaminant levels for the volatile organic contaminants (VOCs) are listed in Table 4, which is incorporated herein and appears at the end of this chapter. The regulatory detection limit (RDL) for all VOCs is 0.0005 mg/L.

(b) The maximum contaminant levels and the regulatory detection limits (RDLs) for the synthetic organic contaminants (SOCs) are listed in Table 5, which is incorporated herein and appears at the end of this chapter.

(5) MICROBIOLOGICAL – This subsection applies to all public water systems. Monitoring requirements to demonstrate compliance with this subsection are defined in Rule 62-550.518, F.A.C.

(a) The maximum contaminant level is based on the presence or absence of total coliforms in a sample, rather than coliform density. For the purposes of the public notice requirements in Rule 62-560.410, F.A.C., a violation of the standards in this paragraph poses a non-acute risk to health.

1. For a system which collects at least 40 samples per month, if no more than 5.0 percent of the samples collected during a month are total coliform-positive, the system is in compliance with the maximum contaminant level for total coliforms.

2. For a system which collects fewer than 40 samples per month, if no more than one sample collected during a month is total coliform-positive, the system is in compliance with the maximum contaminant level for total coliforms.

(b) Any fecal coliform-positive repeat sample or *E. coli*-positive repeat sample, or any total coliform-positive repeat sample following a fecal coliform-positive or *E. coli*-positive routine sample is a violation of the maximum contaminant level for total coliforms. For the purposes of the public notification requirements in Rule 62-560.410, F.A.C., this is a violation that poses an acute risk to health.

(c) A public water system shall determine compliance with the maximum contaminant level for total coliforms in paragraphs (a) and (b) of this subsection for each month (or quarter for transient non-community water systems that use only ground water not

under the direct influence of surface water and that serve 1,000 or fewer persons) in which it is required to monitor for total coliforms.

(6) RADIONUCLIDES – This subsection applies only to community water systems. The following are the maximum contaminant levels (MCLs) and regulatory detection limits (RDLs) for radionuclides:

(a) Naturally occurring radionuclides:

MAXIMUM CONTAMINANT LEVELS
FOR RADIONUCLIDES

CONTAMINANT	MAXIMUM CONTAMINANT LEVEL
Combined radium226 and radium228	5 pCi/L
Gross alpha particle activity including radium226 but excluding radon and uranium	15 pCi/L
Uranium	30 ug/L

pCi/L = picoCuries per liter
ug/L = micrograms per liter

(b) Man-made radionuclides:

1. The average annual concentration of beta particle and photon radioactivity from man-made radionuclides in drinking water shall not produce an annual dose equivalent to the body or any internal organ greater than 4 millirem/year.

2. Except for those radionuclides listed below, the concentration of man-made radionuclides causing 4 mrem total body or organ dose equivalents shall be calculated on the basis of a 2 liter per day drinking water intake using the 168-hour data list in "Maximum Permissible Body Burdens and Maximum Permissible Concentration of Radionuclides in Air or Water for Occupational Exposure," NBS Handbook 69 as amended August 1963, U. S. Department of Commerce.

Average Annual Concentration Assumed to Produce
an Exposure of 4 millirem/year:

RADIONUCLIDE	CRITICAL ORGAN	pCi/L
Tritium	total body	20,000
Strontium90	bone marrow	8

pCi/L = picoCuries per liter

3. If two or more radionuclides are present, the sum of their annual dose equivalent to the total body or to any organ shall not exceed 4 millirem/year.

(c) For the purposes of monitoring for gross alpha particle activity, radium-226, radium-228, uranium, and beta particle and photon radioactivity in drinking water, the following regulatory detection limits shall be used:

CONTAMINANT	REGULATORY DETECTION LIMIT
Gross alpha particle activity	3 pCi/L
Radium-226	1 pCi/L
Radium-228	1 pCi/L
Uranium	1 ug/L
Tritium	1,000 pCi/L
Strontium-89	10 pCi/L
Strontium-90	2 pCi/L
Iodine-131	1 pCi/L
Cesium-134	10 pCi/L
Gross beta	4 pCi/L
Other radionuclides	1/10 of the applicable limit

pCi/L = picoCuries per liter
ug/L = micrograms per liter

Specific Authority 403.861(9) FS. Law Implemented 403.852(12), 403.853(1) FS. History–New 11-19-87, Formerly 17-22.210, Amended 1-18-89, 5-7-90, 1-3-91, 1-1-93, 1-26-93, 7-4-93, Formerly 17-550.310, Amended 9-7-94, 8-1-00, 11-27-01, 4-14-03, 4-25-03, 11-28-04.

FLORIDA POWER & LIGHT COMPANY

Consent Order
in OGC Case Number 06-0744
FPL Martin Plant Public Water System
PWS #4431748

RRL-2
DOCKET NO. 070007-EI
FPL WITNESS: R.R. LABAUVE
EXHIBIT _____
PAGES 1-11

Department of Environmental Protection

Jeb Bush
Governor

Southeast District
400 N. Congress Avenue, Suite 200
West Palm Beach, Florida 33401

Colleen M. Castille
Secretary

SEP 2 2 2006

CERTIFIED MAIL #7006 0100 0002 8783 9555
RETURN RECEIPT REQUESTED

Craig Arcari, General Manager
Florida Power & Light Company – Martin Plant
P.O. Box 176
Indiantown, Florida 34954

Re: Consent Order in OGC Case Number 06-0744
FPL Martin Plant Public Water System PWS #4431748

Dear Mr. Arcari:

Enclosed for your implementation is the fully executed and filed Consent Order in the above-styled case. Please familiarize yourself with the compliance dates and terms of the Consent Order so the complete and timely performance of those obligations is accomplished.

Thank you for your cooperation in this matter. If you have any questions concerning the Consent Order, please contact **Michele Owens** of this office at 561/681-6700.

Sincerely,

Kevin R. Neal 9/22/06

Kevin R. Neal Date
District Director
Southeast District Office
KRN/LAH/TRB/mo

Enclosure (all)

cc: Jerry Toney – Drinking Water Compliance Section, DEP/PSL
Lea Crandall – OGC, MS-35, DEP/Tallahassee

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI **EXHIBIT** 8
COMPANY Florida Power + Light
WITNESS R.R. LaBauve (RRL-2)
DATE 11-06-07

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION, Complainant, vs. FLORIDA POWER & LIGHT COMPANY, Respondent.	IN THE OFFICE OF THE SOUTHEAST DISTRICT OGC FILE NO. 06-0744

CONSENT ORDER

This Consent Order is entered into between the State of Florida Department of Environmental Protection ("Department") and Florida Power & Light Company ("Respondent") to reach settlement of certain matters at issue between the Department and Respondent.

The Department finds and the Respondent neither admits nor denies the following:

1. The Department is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources and to administer and enforce the provisions of the Florida Safe Drinking Water Act, Sections 403.850 et seq., Florida Statutes, and the rules promulgated thereunder, Title 62, Florida Administrative Code. The Department has jurisdiction over the matters addressed in this Consent Order.

2. Respondent is a "person" within the meaning of Section 403.852(5), Florida Statutes.

3. Respondent is the owner and is responsible for the operation of a nontransient noncommunity public water system ("System"), PWS #4431748, located on Warfield Boulevard, northwest of Indiantown, Martin County, Florida, which serves the Florida Power & Light Martin Power Plant.

4. The Department finds that Respondent is in violation of Rule 62-550.310(3), Fla. Admin. Code which establishes the maximum contaminant levels (MCLs) for total

trihalomethanes (TTHMs) and haloacetic acids (five) (HAA5s) as 0.080 milligrams per liter (mg/L) and 0.060 mg/L, respectively. The average results for samples collected from the System on March 15, 2005, April 12, 2005, September 14, 2005, and December 28, 2005, and analyzed for total trihalomethanes (TTHMs) and haloacetic acids (five) (HAA5s) are 0.173 milligrams per liter (mg/L) and 0.132 mg/L, respectively.

Having reached a resolution of the matter the Department and the Respondent mutually agree and it is

ORDERED:

5. Respondent shall comply with the following corrective actions within the stated time periods:

a. By September 1, 2006, Respondent shall retain the services of a Florida-registered professional engineer to evaluate the System and either submit an application, along with any required application fees, to the Department for a permit to construct any modifications needed to address the MCL exceedances, or, if the evaluation determines that no additional treatment is needed, a plan of corrective action ("Plan") with interim milestone dates, signed and sealed by a Florida-registered Professional Engineer.

b. The Department shall review the application/Plan submitted pursuant to paragraph 5.a. above. In the event additional information, modifications or specifications are necessary to process the application/Plan, the Department shall issue a written request for information ("RFI") to Respondent for such information. Respondent shall accordingly submit the requested information in writing to the Department within 30 days of receipt of the request. Respondent shall provide all information requested in any additional RFIs issued by the Department within 30 days of receipt of each request. Within 60 days of the date the Department receives the application/Plan pursuant to paragraph 5.a. above, Respondent shall provide all information necessary to complete the application/Plan. The Department shall notify Respondent in writing of Department approval of the Plan.

c. Within 180 days of issuance of any required permit(s), or written Department approval, if no permit is required, Respondent shall complete the Department-approved modifications in accordance with the permit/written approval issued pursuant to paragraphs 5.a. and 5.b. above, and submit to the Department the engineer's certification of completion of construction, along with all required supporting documentation. Respondent shall receive written Department clearance prior to placing the System modifications into service.

d. Respondent shall continue to sample quarterly for TTHMs and HAA5s. Results shall be submitted to the Department within ten (10) days of Respondent's receipt of the results.

e. In the event that the modifications approved by the Department pursuant to paragraphs 5.a. and b. are determined to be inadequate to resolve the MCL exceedances, the Department will notify the Respondent in writing. Within 30 days of receipt of written notification from the Department that the results of the quarterly sampling indicate that the System modifications have not resolved the violations, Respondent shall submit another proposal to address the MCL exceedances. Respondent shall provide all information requested in any RFIs issued by the Department within 30 days of receipt of each request. Within 60 days of the date the Department receives the application pursuant to this paragraph, Respondent shall provide all information necessary to complete the application.

f. Within two years of the effective date of this Consent Order, Respondent shall complete all corrective actions needed to resolve the MCL exceedances and submit written certification of completion to the Department for all modifications.

g. Respondent shall continue to issue public notice regarding the MCL exceedances every 90 days in accordance with Rule 62-560.410(1), Fla. Admin. Code, until the Department determines that System is in compliance with all MCLs. Respondent shall submit certification of delivery of public notice, using DEP Form 62-555.900(22), to the Department within ten days of issuing each public notice.

6. Within 30 days of the effective date of this Consent Order, Respondent shall reimburse the Department for costs and expenses in the amount of $500.00 which were incurred by the Department during the investigation of this matter and the preparation and tracking of this Consent Order. Payment shall 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."

7. Respondent agrees to pay the Department stipulated penalties in the amount of $100.00 per day for each and every day Respondent fails to timely comply with any of the requirements of paragraphs 5 and 6 of this Consent Order. A separate stipulated penalty shall be assessed for each violation of this Consent Order. Within 30 days of written demand from the Department, Respondent shall make payment of the appropriate stipulated penalties to "The Department of Environmental Protection" by cashier's check or money order and shall include the OGC number assigned to this Consent Order and the notation "Ecosystem Management and Restoration Trust Fund". Payment shall be sent to the Department of Environmental Protection, 400 North Congress Avenue, Suite 200, West Palm Beach, FL 33401. The Department may make demands for payment at any time after violations occur. Nothing in this paragraph shall prevent the Department from filing suit to specifically enforce any of the terms of this Consent Order. Any penalties assessed under this paragraph shall be in addition to the $500.00 agreed to in paragraph 6 of this Consent Order.

8. If any event, including administrative or judicial challenges by third parties unrelated to the Respondent, occurs which causes delay or the reasonable likelihood of delay, in complying with the requirements of this Consent Order, Respondent shall have the burden of proving the delay was or will be caused by circumstances beyond the reasonable control of the Respondent and could not have been or cannot be overcome by Respondent's due diligence. Economic circumstances shall not be considered circumstances beyond the control of Respondent, nor shall the failure of a contractor, subcontractor, materialman or other agent

(collectively referred to as "contractor") to whom responsibility for performance is delegated to meet contractually imposed deadlines be a cause beyond the control of Respondent, unless the cause of the contractor's late performance was also beyond the contractor's control. Upon occurrence of an event causing delay, or upon becoming aware of a potential for delay, Respondent shall notify the Department's Southeast District Office in West Palm Beach orally within 72 hours or within three working days and shall, within ten calendar days of oral notification to the Department, notify the Department in writing of the anticipated length and cause of the delay, the measures taken or to be taken to prevent or minimize the delay and the timetable by which Respondent intends to implement these measures. If the parties can agree that the delay or anticipated delay has been or will be caused by circumstances beyond the reasonable control of Respondent, the time for performance of one or more of the requirements hereunder shall be extended for a period equal to the agreed delay resulting from such circumstances. Such agreement shall adopt all reasonable measures necessary to avoid or minimize delay. Failure of Respondent to comply with the notice requirements of this Paragraph in a timely manner shall constitute a waiver of Respondent's right to request an extension of time for compliance with the requirements of this Consent Order.

9. Persons who are not parties to this Consent Order, but whose substantial interests are affected by this Consent Order, have a right, pursuant to Sections 120.569 and 120.57, Florida Statutes, to petition for an administrative hearing on it. The Petition must contain the information set forth below and must be filed (received) at the Department's Office of General Counsel, 3900 Commonwealth Boulevard, MS# 35, Tallahassee, Florida 32399-3000 within 21 days of receipt of this notice. A copy of the Petition must also be mailed at the time of filing to the District Office named above at the address indicated. Failure to file a petition within the 21 days constitutes a waiver of any right such person has to an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes.

10. The petition shall contain the following information:

a. The name, address, and telephone number of each petitioner; the Department's Consent Order identification number and the county in which the subject matter or activity is located;

b. A statement of how and when each petitioner received notice of the Consent Order;

c. A statement of how each petitioner's substantial interests are affected by the Consent Order;

d. A statement of the material facts disputed by petitioner, if any;

e. A statement of facts which petitioner contends warrant reversal or modification of the Consent Order;

f. A statement of which rules or statutes petitioner contends require reversal or modification of the Consent Order;

g. A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Consent Order.

11. If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this Notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the subject Consent Order have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 21 days of receipt of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Sections 120.569 and 120.57, Florida Statutes, and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-106.205, Florida Administrative Code.

12. A person whose substantial interests are affected by the Consent Order may file a timely petition for an administrative hearing under Sections 120.569 and 120.57, Florida

Statutes, or may choose to pursue mediation as an alternative remedy under Section 120.573, Florida Statutes, before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for pursuing mediation are set forth below.

13. Mediation may only take place if the Department and all the parties to the proceeding agree that mediation is appropriate. A person may pursue mediation by reaching a mediation agreement with all parties to the proceeding (which include the Respondent, the Department, and any person who has filed a timely and sufficient petition for a hearing) and by showing how the substantial interests of each mediating party are affected by the Consent Order. The agreement must be filed in (received by) the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, MS #35, Tallahassee, Florida 32399-3000, within 10 days after the deadline as set forth above for the filing of a petition.

14. The agreement to mediate must include the following:

a. The names, addresses, and telephone numbers of any persons who may attend the mediation;

b. The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time;

c. The agreed allocation of the costs and fees associated with the mediation;

d. The agreement of the parties on the confidentiality of discussions and documents introduced during mediation;

e. The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen;

f. The name of each party's representative who shall have authority to settle or recommend settlement;

g. Either an explanation of how the substantial interests of each mediating party will be affected by the action or proposed action addressed in this notice of intent or a

statement clearly identifying the petition for hearing that each party has already filed, and incorporating it by reference; and

h. The signatures of all parties or their authorized representatives. As provided in Section 120.573, Florida Statutes, the timely agreement of all parties to mediate will toll the time limitations imposed by Sections 120.569 and 120.57, Florida Statutes, for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such a modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above, and must therefore file their petitions within 21 days of receipt of this notice. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57, Florida Statutes, remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

15. Respondent shall allow all authorized representatives of the Department access to the facility at reasonable times for the purpose of determining compliance with the terms of this Consent Order and the rules and statutes of the Department.

16. All submittals and payments required by this Consent Order to be submitted to the Department shall be sent to the Florida Department of Environmental Protection, Southeast District Water Facilities Program, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida, 33401.

17. This Consent Order is a settlement of the Department's civil and administrative authority arising under Florida law to resolve the matters addressed herein. This Consent Order is not a settlement of any criminal liabilities, which may arise under Florida law, nor is it a

settlement of any violation which may be prosecuted criminally or civilly under federal law and which Respondent may defend.

18. The Department hereby expressly reserves the right to initiate appropriate legal action to prevent or prohibit any violations arising after the date of this Consent Order of applicable statutes, or the rules promulgated thereunder that are not specifically addressed by the terms of this Consent Order.

19. The terms and conditions set forth in this Consent Order may be enforced in a court of competent jurisdiction pursuant to Sections 120.69 and 403.121, Florida Statutes. Failure to comply with the terms of this Consent Order shall constitute a violation of Section 403.859, Florida Statutes.

20. The Department, for and in consideration of the complete and timely performance by Respondent of the obligations agreed to in this Consent Order, hereby waives its right to seek judicial imposition of damages or civil penalties for alleged violations.

21. Respondent is fully aware that a violation of the terms of this Consent Order may subject Respondent to judicial imposition of damages, civil penalties up to $5,000.00 per day per violation, and criminal penalties, except as limited by the provisions of this Consent Order.

22. Except as otherwise provided herein, entry of this Consent Order does not relieve Respondent of the need to comply with applicable federal, state or local laws, regulations or ordinances.

23. No modifications of the terms of this Consent Order shall be effective until reduced to writing and executed by both Respondent and the Department.

24. Respondent acknowledges and waives its right to an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes, on the terms of this Consent Order. Respondent acknowledges its right to appeal the terms of this Consent Order pursuant to Section 120.68, Florida Statutes, and waives that right upon signing this Consent Order.

25. This Consent Order is a final order of the Department pursuant to Section 120.52(7), Florida Statutes, and it is final and effective on the date filed with the Clerk of the

Department unless a Petition for Administrative Hearing is filed in accordance with Chapter 120, Florida Statutes. Upon the timely filing of a petition this Consent Order will not be effective until further order of the Department.

FOR THE RESPONDENT:

8/31/2006

Craig Arcari, General Manager Date
Florida Power & Light Company - Martin Plant
P.O. Box 176
Indiantown, Florida 34954

DONE AND ORDERED this 22 day of Sept., 2006, in West Palm Beach, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

9/22/06

Kevin R. Neal Date
District Director
Southeast District

FILED, on this date, pursuant to §120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Linda Iscka/pat

Clerk

9-22-06

Date

Copies furnished to:
Lea Crandall, Agency Clerk, MS 35
Drinking Water Compliance Section, FDEP/PSL

FLORIDA POWER & LIGHT COMPANY

Golder Associates Inc.
FPL Martin Plant
Potable Water System
DBP (THM & HAA5) Analysis

RRL-3
DOCKET NO. 070007-EI
FPL WITNESS: R.R. LABAUVE
EXHIBIT _____
PAGES 1-107

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 9
COMPANY Florida Power & Light
WITNESS R.R. LaBauve (RRL-3)
DATE 11-06-07

Golder Associates Inc.

3730 Chamblee Tucker Road
Atlanta, GA USA 30341
Telephone (770) 496-1893
Fax (770) 934-9476

August 29,2006

063-3495

FPL Martin Plant
PO Box 176
Indiantown FL 34956

Attn: Willie J. Welch, Production Support - Chemistry/ Environmental Leader

RE: FPL MARTIN PLANT
POTABLE WATER SYSTEM
DBP (THM & HAA5) ANALYSIS

Dear Willie:

Golder Associates Inc. (Golder) is pleased to send you this final report to provide recommendations as to how to achieve compliance with the drinking water limits for trihalomethanes and haloacetic acids within the Martin Plant potable water system.

Very truly yours,

GOLDER ASSOCIATES INC.

James J. Daly, P.E
Associate

Harold A. Frediani, Jr., P.E., P.H.
Senior Water Resources Engineer

JJCP/sdp

Florida P.E. Number 36394
Certificate of Authorization No. 1670

Attachments

X:\Clients\Florida Power and Light\063-3495-Martin DBPs\Report\MartinDBPReport8-27-06.doc

HAROLD A. FREDIANI JR. LICENSE No.36394 STATE OF FLORIDA PROFESSIONAL ENGINEER

1.0 INTRODUCTION 1

2.0 BACKGROUND 2

3.0 DISCUSSION 3
3.1 Existing Equipment 3
3.2 Alternative Disinfectants 3
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4.0 CONCLUSIONS AND RECOMMENDATIONS 4

5.0 PLAN AND MILESTONE DATES 5

APPENDIX A. SYSTEM OPERATIONAL MANUAL DRAWINGS 1

APPENDIX B. CONSENT ORDER 2

APPENDIX C. CALCULATIONS 3

1.0 INTRODUCTION

FPL retained Golder to assist in analyzing the Martin Plant potable water treatment system to assist FPL with compliance with Florida Department of Environmental Protection (FDEP) drinking water limits on Disinfection Byproducts (DBPs). Golder has performed a site visit to inspect the potable water system, reviewed well data, performed a literature search, and provided recommendations as to how to achieve compliance with the drinking water limits for trihalomethanes and haloacetic acids. This report documents the results of those tasks, and includes a corrective action plan, in the form of project milestones suitable for submittal to FDEP in response to their Consent Order.

2.0 BACKGROUND

The Martin potable water system serves Units 1 through 4 of the FPL Martin Plant, located in Indiantown, Florida. The original system was built with Units 1 and 2, and is depicted on the system Operational Manual drawings which are shown in Appendix A. A simplified flow diagram is shown in Figure 1. Water is pumped from the well through a static mixer in which liquid sodium hypochlorite is applied. The water then enters a multiple tray aerator. At the bottom of the aerator, the water is collected in the aerator tank, from which it is pumped in parallel to three mixed media (gravel, garnet, sand and anthracite) filters. From the filters, a portion of the water can be sent through softeners; however, most of the time all of the water is sent on to the activated carbon filter. From the carbon filter, the water is sent to the 15,000 gallon holding tank. Liquid sodium hypochlorite is injected directly into the holding tank. A recirculation pump is energized all the time to pressurize the distribution system to 70 psi; this pump recycles water back to the holding tank when necessary.

When Units 3 and 4 were added, the system was extended, and another pump, hydro-pneumatic tank, and sodium hypochlorite injection system were added.

The system currently is experiencing difficulty meeting the Disinfection Byproduct Rule (62-550 FAC, Table 3), which limits the level of Total Trihalomethanes (TTHM) to no more than 80 ug/L and HaloAcetic Acids Five (HAA5) to no more than 60 ug/L. FPL provided data taken since the DBP rule went into effect. The data are presented in Table 1. All but one of the samples were taken at the Maximum Residence Time (MRT) location, which is in the Units 3&4 laboratory building. The other sample was taken at the Point of Entry (POE) to the distribution system., which is at the outlet to the holding tank.

The TTHM data, along with the standard of 80 ug/L, are plotted in Figure 2. These data indicate that virtually all of the TTHM in the system is in the form of chloroform. The HAA5 data, along with the standard of 60 ug/L, are plotted in Figure 3. These data indicate that virtually all of the HAA5 is in the form of either di- or tri-chloroacetic acid (DCA or TCA). These findings are consistent with the disinfectant being used, which does not contain bromine, but has as the active disinfectant hypochlorite ion ($HClO_3^-$).

Figure 4 plots the three contributory compounds as a function of the disinfectant residual. Based on these data, it can be concluded that the DBP levels are not a function of the disinfection residual level. Therefore, it can be surmised that they are a function of the raw water organic content level.

FPL is in receipt of a proposed Consent Order (CO, see Appendix B) from FDEP to determine whether any modifications to the system are necessary, or whether the existing system can be corrected to achieve compliance. If modifications are necessary, the CO requires FPL to submit an application to modify the existing permit. If modifications are not necessary, the CO requires that FPL submit a plan of corrective action ("Plan") with interim milestone dates, signed and sealed by a Florida-registered Professional Engineer.

3.0 DISCUSSION

3.1 Existing Equipment

Within the existing system, there are only two mechanisms for removal of either DBPs or the DBP precursors (organic compounds). The aerator is intended to strip volatile organics out of the water, while the activated carbon filter removes them by adsorption. Since the aerator is the first of these processes that the influent water encounters, it appears that the aerator could accomplish sufficient treatment to achieve the required reduction in concentration of chloroform which is considered volatile. The aerator would not be expected to remove the DCA and TCA as well since they are reported to be of low volatility; however, some removal should be accomplished. A preliminary calculation (see Appendix C. Calculations) indicates that the aerator should work well if it's blower provides about 200 cubic feet per minute of air. Neither the plant operating manual, nor examination of the equipment, gives any indication of the original design capacity of the aerator. A necessary step in the future will be to measure the air flow through the aerator.

The carbon filter can be expected to remove all three of the compounds in question. Based on the flow rate, chloroform content, and size of the unit (39 cubic feet), an Empty Bed Contact time (EBCT) of 5.8 minutes has been calculated. This is borderline relative to AWWA recommendations of 5 to 25 minutes. However, two options are available to increase the EBCT using existing equipment. The first option would be to convert one or both of the softeners to contain activated carbon. The softeners are approximately 2 feet in diameter and 3 feet high, with an estimated volume of about 19 cubic feet between them. The second option would be to replace the anthracite media in the multi-media filters with activated carbon. Each filter contains about 7 cubic feet of anthracite, for a total of 14 cubic feet.. Using both of these options would increase the EBCT to about 11 minutes. Another option would be to inject powdered activated carbon (PAC) into the aerator tank, to adsorb the TTHMs and HAA5s and then be removed in the multi-media filters.

3.2 Alternative Disinfectants

Potential alternative disinfectants are chlorine dioxide, ultraviolet light, and ozone. Chlorine dioxide does not produce TTHMs, but produces chlorite, which is also regulated under the DBP rule. Ozone or UV can not be used because neither leaves a residual, which is required in a distribution system. In general, switching to an alternative disinfectant would not be expected to be as effective as improving the existing treatment system.

3.3 New Equipment

Either the aerator or the carbon filter could be replaced with newer, larger versions of the same equipment. Neither the carbon filter nor the aerator were sized when DBPs were a concern, and could certainly be replaced with larger units. This would provide the advantage of longer contact time.

4.0 CONCLUSIONS AND RECOMMENDATIONS

The literature review indicates (See Appendix C. Calculations for references) that the two DBP treatment technologies within the Martin system, namely aeration and activated carbon filtration, are presently the best technologies for the removal of DBPs. Therefore, it is concluded that no additional treatment technology is necessary, and the existing system needs corrective action to achieve the applicable limits. The first activity that should be undertaken is to perform measurements on the aerator to determine whether it is sized correctly and is working properly. Golder recommends that the following actions be taken:

- Measure the dimensions of the aerator column and stack;
- Measure the air velocity leaving the aerator when it is operating;
- Sample and analyze the inlet and outlet water at the aerator for TTHM and HAA5 to determine its removal performance; and
- Sample and analyze for TTHM and HAA5 the inlet and outlet water at the carbon filter, synoptically with the aerator water measurements.

Based on the results of the first three above actions, it can be determined whether the aerator can be enhanced or replaced to accomplish the desired water quality. Results from the fourth action can likewise be used to determine whether additional activated carbon EBCT would be helpful, and if so, how much would be required to be added, either in conjunction with improved aeration or instead of it.

5.0 PLAN AND MILESTONE DATES

This plan with milestone dates is predicated on the longest anticipated schedule and assumes that FDEP will issue one request for additional information, and that the measurements taken will lead to the ultimate decision to replace both the aerator and the carbon filter with new equipment. The interim milestone dates are as follows:

- September 1, 2006 - FPL submits signed Consent Order and signed/sealed corrective action plan;
- September 22, 2006 – FDEP issues written request for additional information (RFI);
- October 23, 2006 – FPL provides additional information to FDEP;
- October 30, 2006 – FDEP issues written approval of the plan;
- November 22, 2006 – FPL completes measurements of physical characteristics of aeration system, and takes synoptic samples of inlet and outlet water for both the aerator and the carbon filter, and sends those samples to the laboratory;
- December 6, 2006 – FPL receives results/report from laboratory;
- January 31, 2007 – Install pilot equipment for testing;
- September 30, 2007 – Complete testing of pilot;
- October 1, 2007 - FPL issues performance specifications to bidders to provide new aerator and carbon filter units;
- November 1, 2007 – FPL receives bids to provide new aerator and carbon filter units;
- December 1, 2007 - FPL awards contract to successful bidder to install new aerator and carbon filter units;
- January 2008 - Installation of new aerator and carbon filter units is complete;
- June 2008 - Testing of new aerator and carbon filter units is complete, FPL submits engineer's certification of completion of construction and required supporting documentation.
- July 2008 - FDEP issues written clearance to place the system modifications into service.

TABLES

Table 1. Monitoring Data

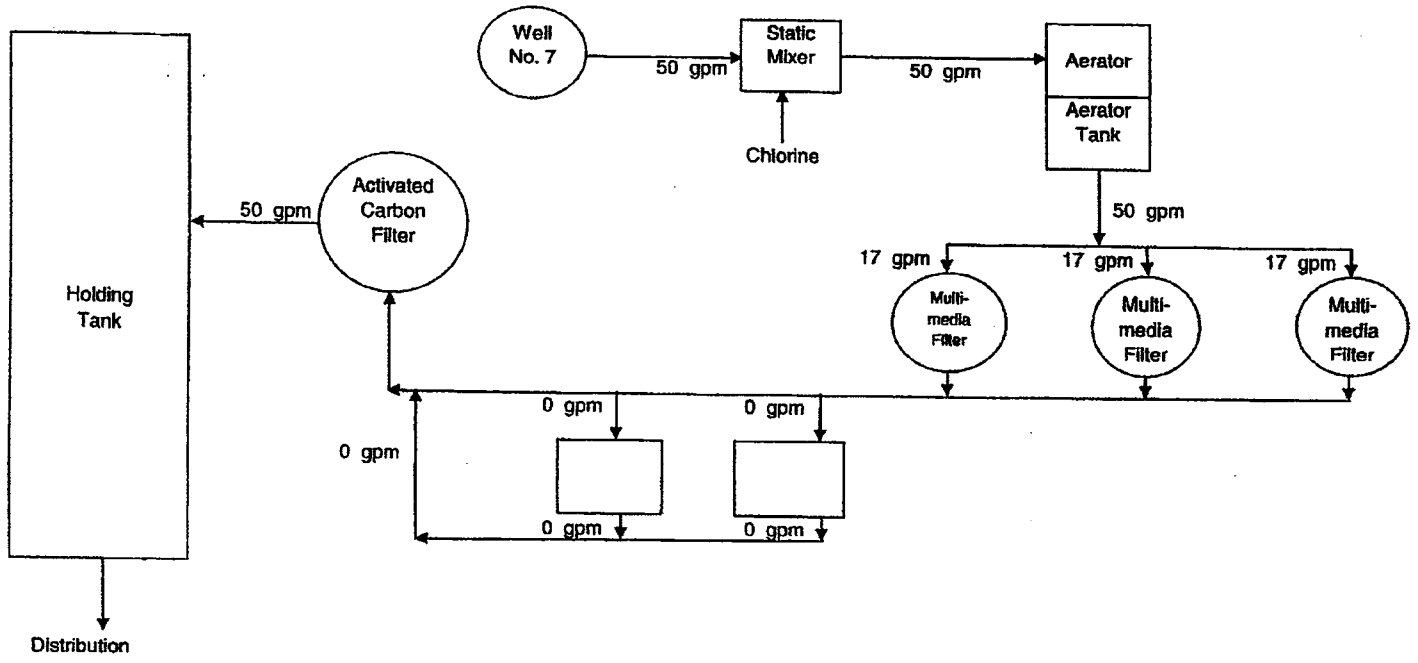
Location	MRT	MRT	MRT	MRT	MRT	MRT	Potable POE
Date	5/25/2006	2/13/2006	12/21/2005	9/14/2005	4/12/2005	3/15/2005	8/25/2004
Monochloroacetic acid - ug/L	0.9	2.8	4	4.7	4.9	0.9	5.3
Dichloroacetic acid - ug/L	46.4	59	54	100	87	33	120
Trichloroacetic acid - ug/L	50.9	41	43	99	64	29	100
Monobromoacetic acid - ug/L	0.28	0.46	0.3	0.5	0.28	0.28	0.28
Dibromoacetic acid - ug/L	0.235	2.6	1.2	0.52	0.8	0.47	1.3
HAA5 - ug/L	97.3	105	100	210	160	63	230
HAAF Standard - ug/L	60	60	60	60	60	60	60
Date	5/25/2006	2/13/2006	12/21/2005	9/14/2005	4/12/2005	3/15/2005	8/25/2004
Chloroform - ug/L	123	160	140	210	160	70	250
Bromoform - ug/L	0.205	0.205	0.205	0.205	0.205	0.205	0.205
Bromodichloromethane - ug/L	27.5	46	23	32	32	13	37
Dibromochloromethane - ug/L	5.02	11	2.5	3.3	3.7	1.4	3.9
TTHM - ug/L	155	210	160	240	190	84	290
TTHM Standard - ug/L	80	80	80	80	80	80	80
Chlorine residual		0.6	1.2	0.4	0.4	1.1	

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FIGURES

Notes: Flows in gpm shown when pump is on.

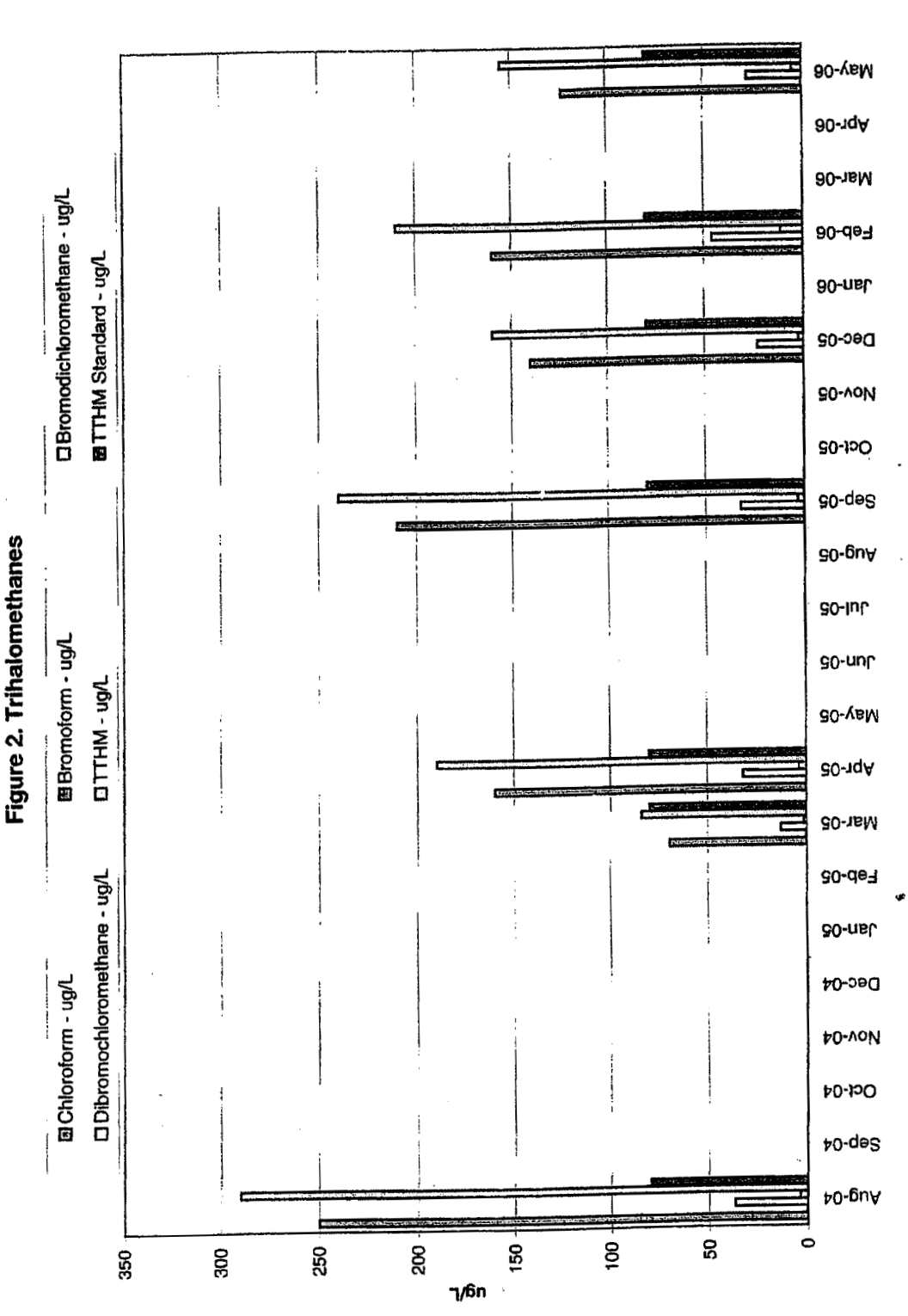
Figure 1. Martin Potable Water Flow Diagram



8/18/2006 4:03 PM

Figures.xls Fgure 1

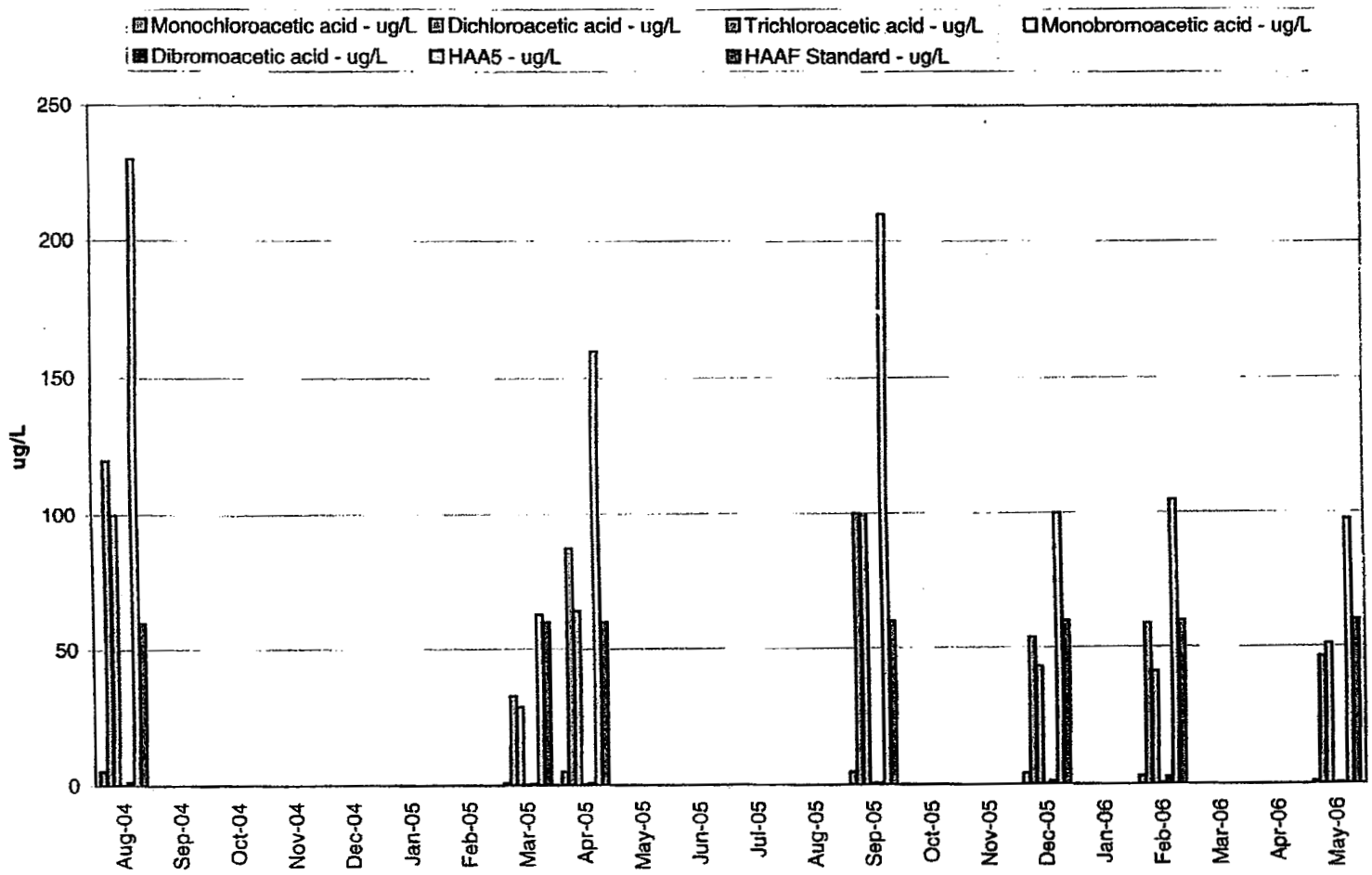
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Figures.xls Figure 2

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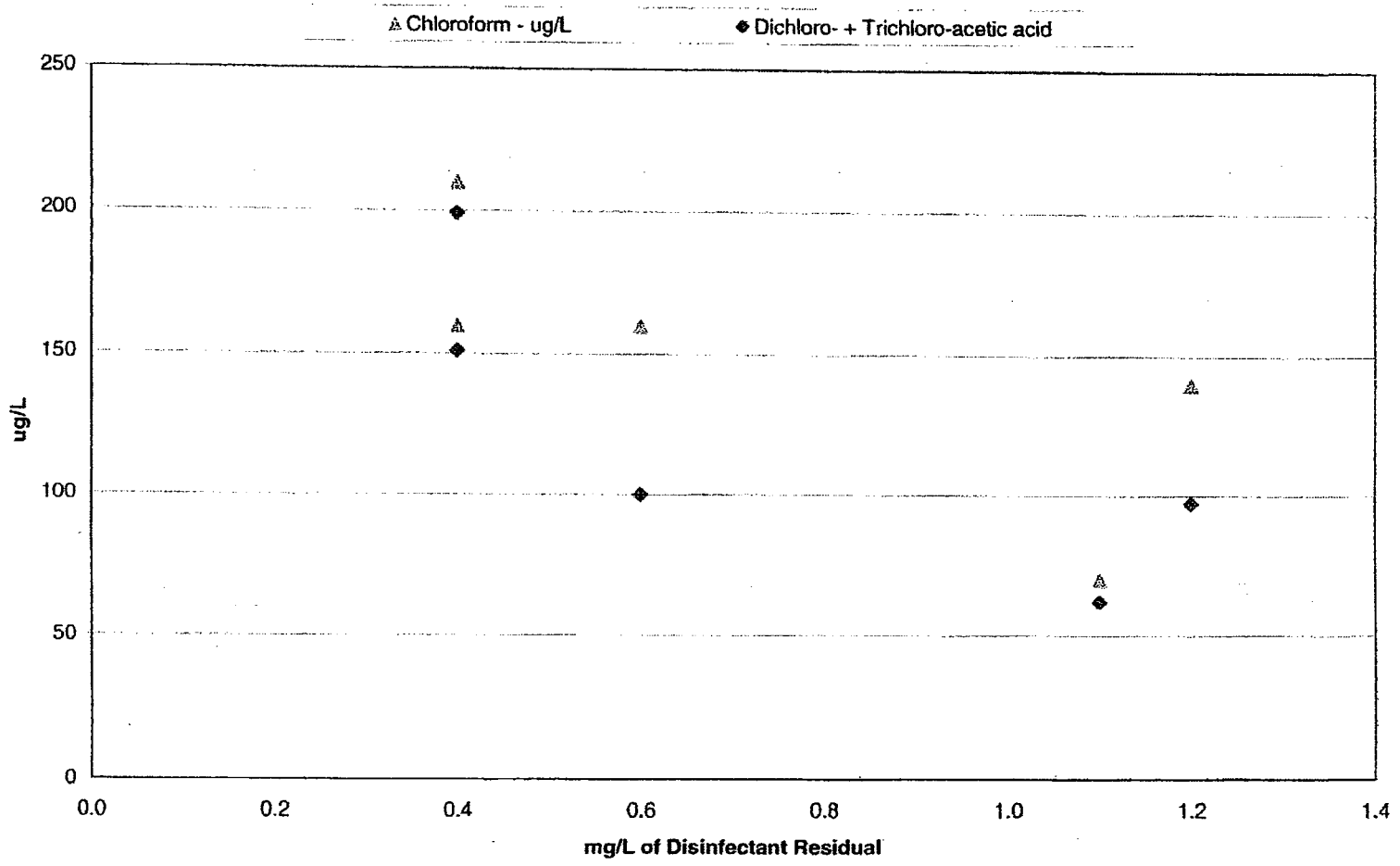
Figure 3. Haloacetic Acids



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Figures.xls Figure 3

Figure 4. Effect of Disinfectant Residual



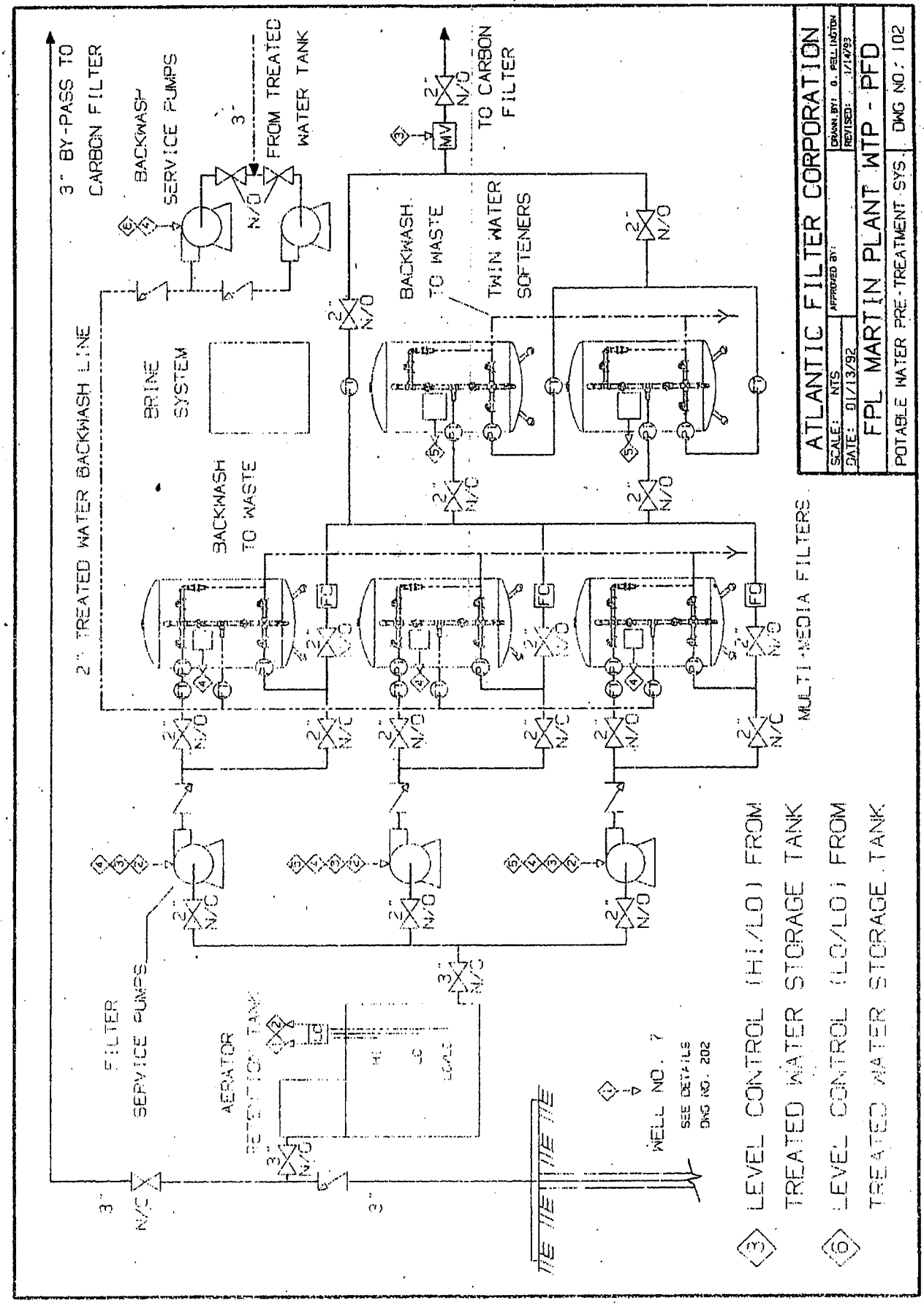
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Figures.xls Figure 4

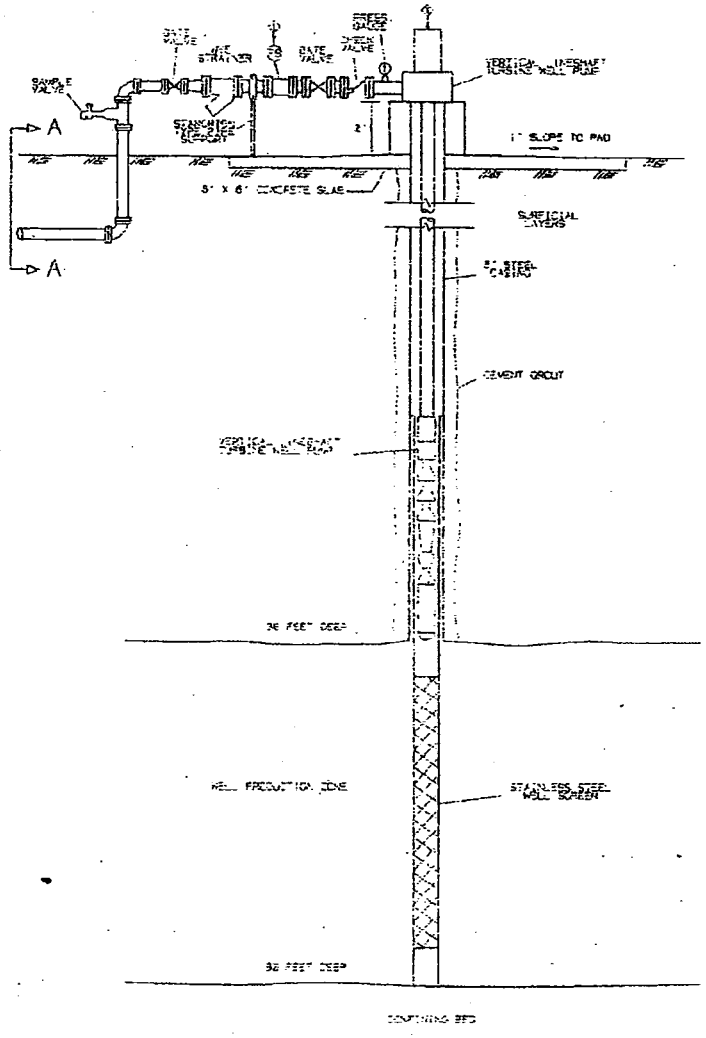
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APPENDICES

APPENDIX A. SYSTEM OPERATIONAL MANUAL DRAWINGS

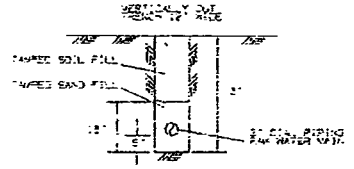

ATLANTIC FILTER CORPORATION
SCALE: NTS
DATE: 01/13/92
APPROVED BY:
DRAWN BY: G. PELLINGTON
REVISED: 1/14/93
FPL MARTIN PLANT WTP - PFD
POTABLE WATER PRE-TREATMENT SYS.
DWG NO.: 102
3" BY-PASS TO CARBON FILTER
BACKWASH SERVICE PUMPS
FROM TREATED WATER TANK
TO CARBON FILTER
2" TREATED WATER BACKWASH LINE
BRINE SYSTEM
BACKWASH TO WASTE
TWIN WATER SOFTENERS
MULTI-MEDIA FILTERS
FILTER SERVICE PUMPS
AERATOR
DETENTION TANK
WELL NO. 7
SEE DETAILS DWG NO. 202
LEVEL CONTROL (HI/LO) FROM TREATED WATER STORAGE TANK
LEVEL CONTROL (LO/LO) FROM TREATED WATER STORAGE TANK

WELL NO. 7 DETAIL



WELL DRILLER'S LOG

0 - 12 FT	TOP SOIL AND SAND
12 - 33 FT	FINE SHELL
33 - 50 FT	SAND ROCK WITH SHELL
50 - 60 FT	SHELL WITH SOME SHELL ROCK
60 - 80 FT	COARSE SHELL
80 - 90 FT	SHELL WITH A LITTLE GREEN MARL
90 - 95 FT	FINE SHELL
95 - 120 FT	VERY FINE SHELL
	VERY FINE SHELL WITH GREEN AND GRAY SANDY MARL AND LIMESTONE TOP HAWTHORNE AT 153 FT

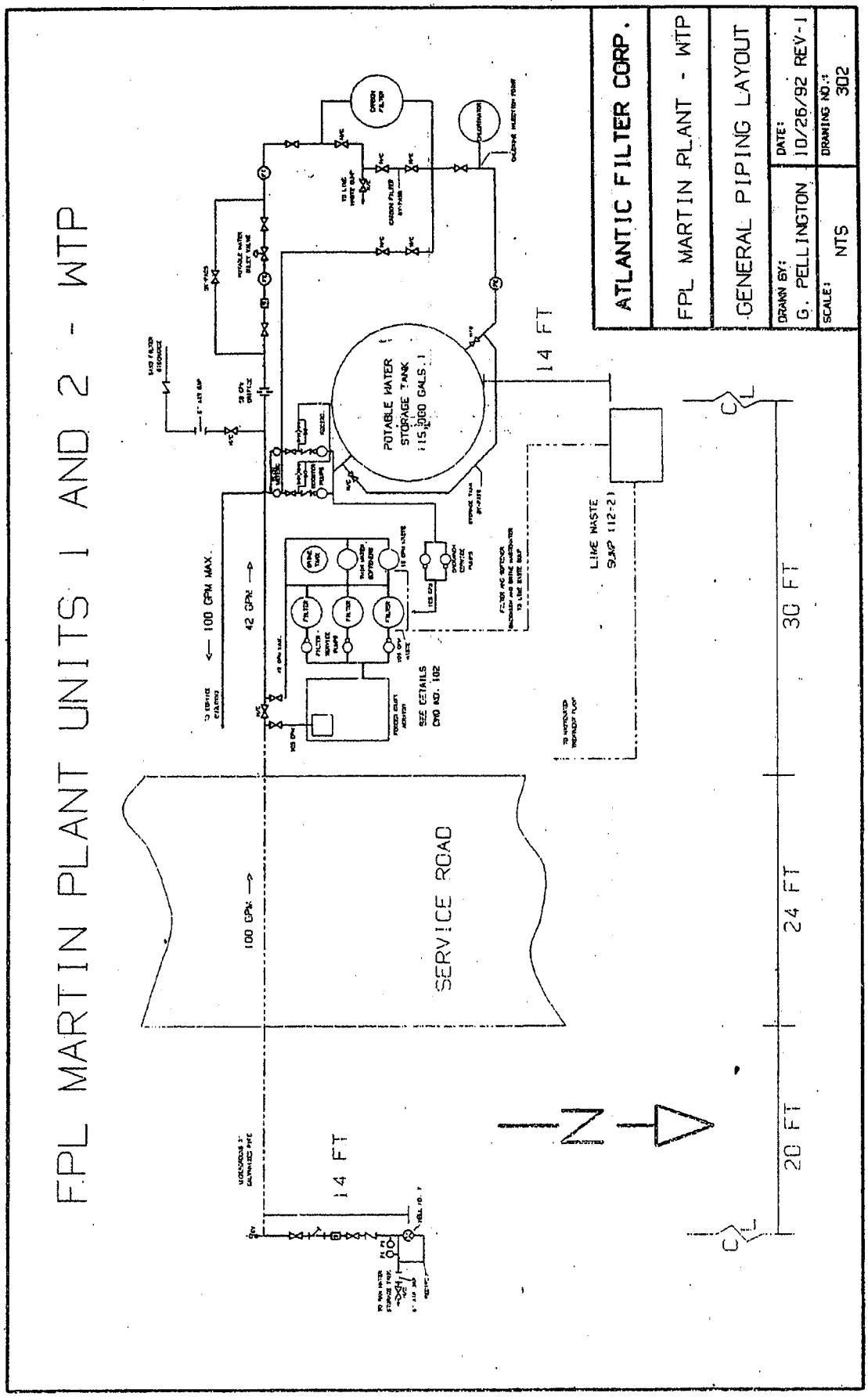


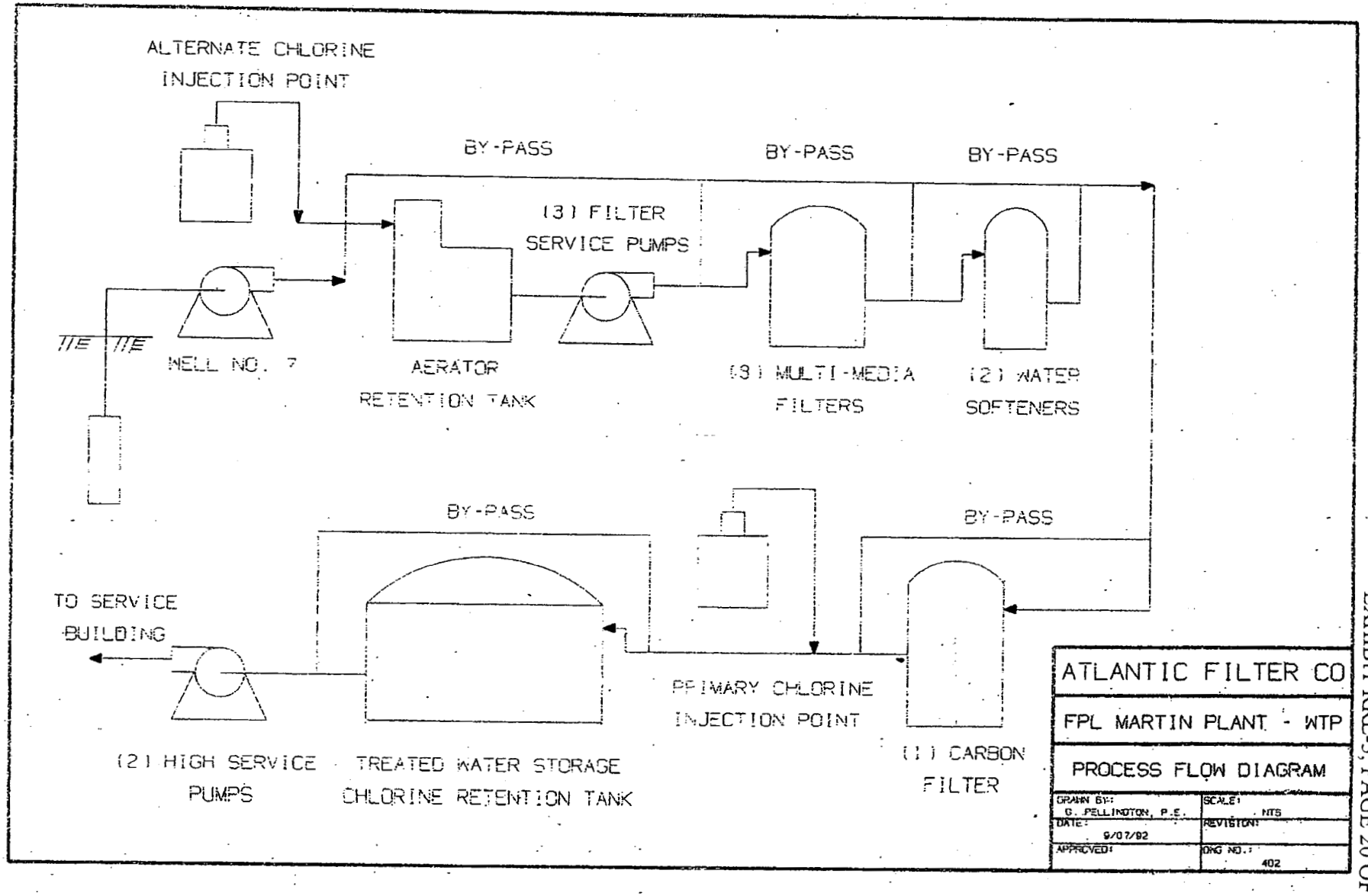
SECTION A-A

RAW WATER MAIN TRENCH DETAIL

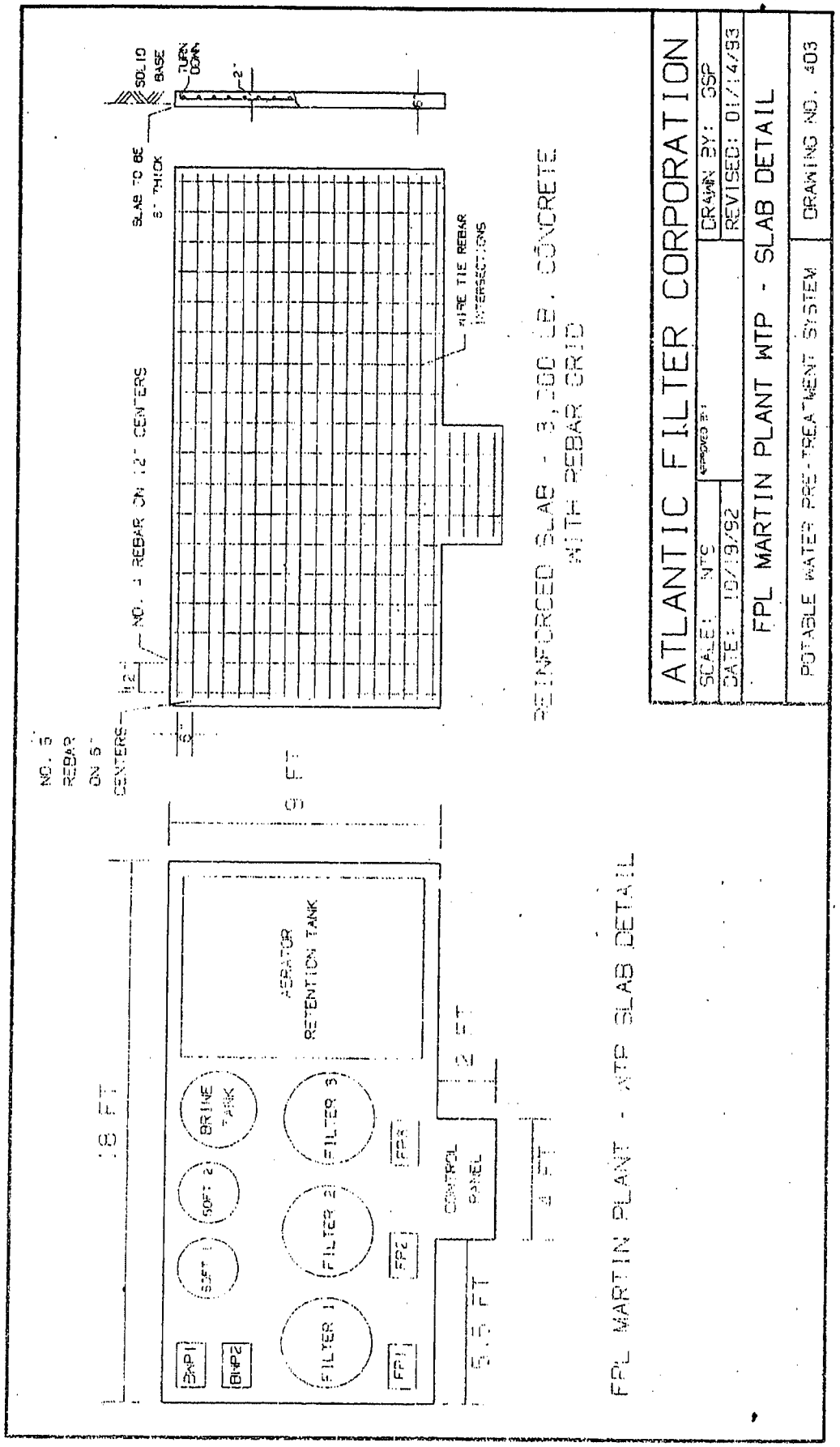
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SCALE: NTS	APPROVED BY:	DRAWN BY: G. PELLINGTON
DATE: 8/13/92		REVISED: 9/27/92
FPL MARTIN PLANT WTP-WELL NO. 7		
WELL NO. 7 DETAILS		DWG NO. 202

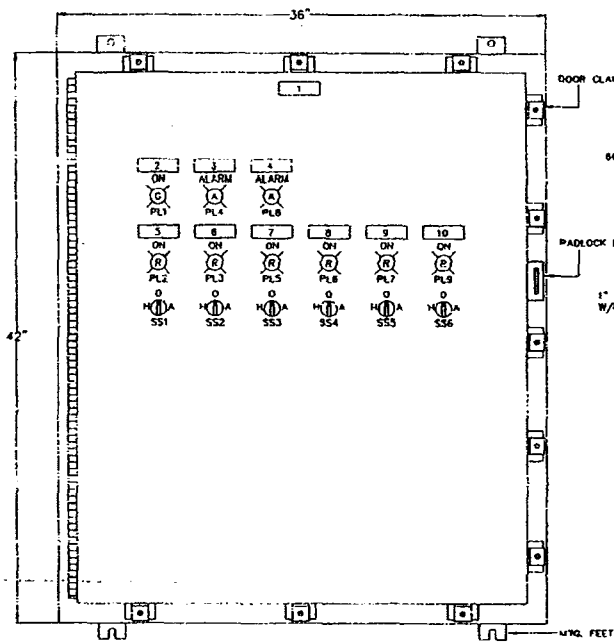
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FPL MARTIN PLANT UNITS 1 AND 2 - WTP
ATLANTIC FILTER CORP.
FPL MARTIN PLANT - WTP
GENERAL PIPING LAYOUT
DRAWN BY: G. PELLINGTON
DATE: 10/26/92 REV-1
SCALE: NTS
DRAWING NO.: 302
POTABLE WATER STORAGE TANK 115,000 GALS.
100 GPM MAX.
42 GPM
100 GPM
SERVICE ROAD
LIME WASTE SUMP (12-2)
SEE DETAILS DWG NO. 102
14 FT
30 FT
24 FT
20 FT
14 FT

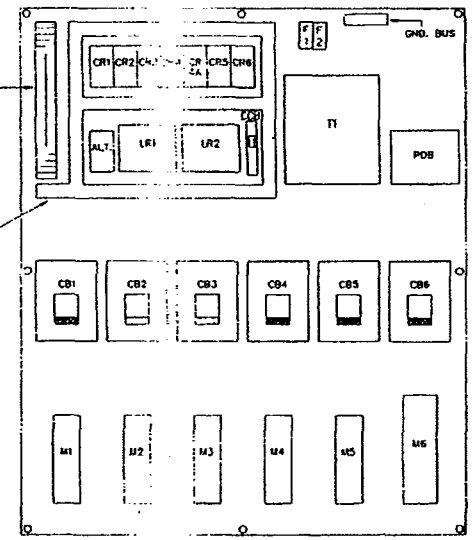


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ATLANTIC FILTER CORPORATION
SCALE: NTS
DATE: 10/19/92
DRAWN BY: GSP
REVISED: 01/14/93
FPL MARTIN PLANT WTP - SLAB DETAIL
POTABLE WATER PRE-TREATMENT SYSTEM
DRAWING NO. 403
REINFORCED SLAB - 3,700 LB. CONCRETE
WITH REBAR GRID
SLAB TO BE 8" THICK
SOLID BASE
TURN DOWN
NO. 4 REBAR ON 12" CENTERS
NO. 5 REBAR ON 5" CENTERS
WIRE TIE REBAR INTERSECTIONS
FPL MARTIN PLANT - WTP SLAB DETAIL
18 FT
9 FT
12 FT
4 FT
5.5 FT
AERATOR RETENTION TANK
BRINE TANK
FILTER 1
FILTER 2
FILTER 3
SOFT 1
SOFT 2
BWP1
BWP2
FP1
FP2
FP3
CONTROL PANEL



FRONT VIEW



SUBPLATE LAYOUT

NAMEPLATE SCHEDULE

1	1" X 3"	PUMP CONTROL PANEL
2	1" X 3"	CONTROL POWER
3	1" X 3"	BACKWASH PUMPS / LOW PRESSURE
4	1" X 3"	RETENTION TANK / LOW LEVEL
5	1" X 3"	BACKWASH SERVICE / PUMP NO.1
6	1" X 3"	BACKWASH SERVICE / PUMP NO.2
7	1" X 3"	FILTER SERVICE / PUMP NO.1
8	1" X 3"	FILTER SERVICE / PUMP NO.2
9	1" X 3"	FILTER SERVICE / PUMP NO.3
10	1" X 3"	WELL NO.7

BILL OF MATERIAL

ITEM	QTY	DESCRIPTION
REMOTE	3	WARRICK 3R6A4 6FT. PVC COATED BRASS PROBES
	1	WARRICK 3R6A0 6FT. BRASS PROBE
	1	WARRICK 3E4A CAST IRON PROBE HOLDER
	2	WARRICK HE1DO INDUCTION RELAYS 120/300V
	1	GLASTIC 2165-18 INSULATOR
	9	ILSCO SLU-35 GROUND LUGS
	6	SQD CLASS 9080 GH-10 END CLAMPS
	1	SQD CLASS 9080 GR-6B END BARRIER
	25	SQD CLASS 9080 GR-6 600V TERMINALS
	1	SQD CLASS 9080 GF-6B END BARRIER
F1,2	2	SQD CLASS 9080 GF-6 FUSE BLOCKS W/ FNQ-6 FUSES
PL1	1	CUTLER HAMMER E34TB120H3X NEMA 4X GREEN PILOT LIGHT
PL4,8	2	CUTLER HAMMER E34TB120H9X NEMA 4X AMBER PILOT LIGHTS
PL2,3,5-7,9	6	CUTLER HAMMER E34TB120H2X NEMA 4X RED PILOT LIGHTS
SS1-6	6	CUTLER HAMMER E34VH8K1-Y1 NEMA 4X 3POS. SEL. SWITCH
MJ	1	CUTLER HAMMER C320KGS1 STARTER AUXILIARY CONTACT
CCB	1	SQD QOU-120 120V 1P 20A CIRCUIT BREAKER
	7	IDEC SR3B05 SOCKETS
CR1-6	7	IDEC RR3B-ULC 3PDT RELAYS (120V)
	1	OMRON PF083A 8 PIN SOCKET
ALT.	1	DIVERSIFIED ELECTRONICS ARA-120-ABA ALTERNATOR
T1	1	ACME TA-2-81219 2KVA 480/120V TRANSFORMER
PDB	1	GOULD 67083 POWER DISTRIBUTION BLOCK
M6	1	CUTLER HAMMER H2012-3 HEATER PACK
M6	1	CUTLER HAMMER A16NONOA SIZE 1 STARTER
M3-5	3	CUTLER HAMMER H2007-3 HEATER PACKS
M1,2	2	CUTLER HAMMER H2009-3 HEATER PACKS
M1-5	5	CUTLER HAMMER AN16BNOA SIZE 0 STARTER (120V)
CB6	1	CUTLER HAMMER FS340040A 480V 3P 40A CIRCUIT BREAKER
CB1-5	5	CUTLER HAMMER FS340015A 480V 3P 15A CIRCUIT BREAKERS
	1	ELECTROMATE E42P36 SUBPANEL
ENCL.	1	ELECTROMATE E42H36B NEMA 4X ENCLOSURE

PUMP CONTROL PANEL
1-REQ'D

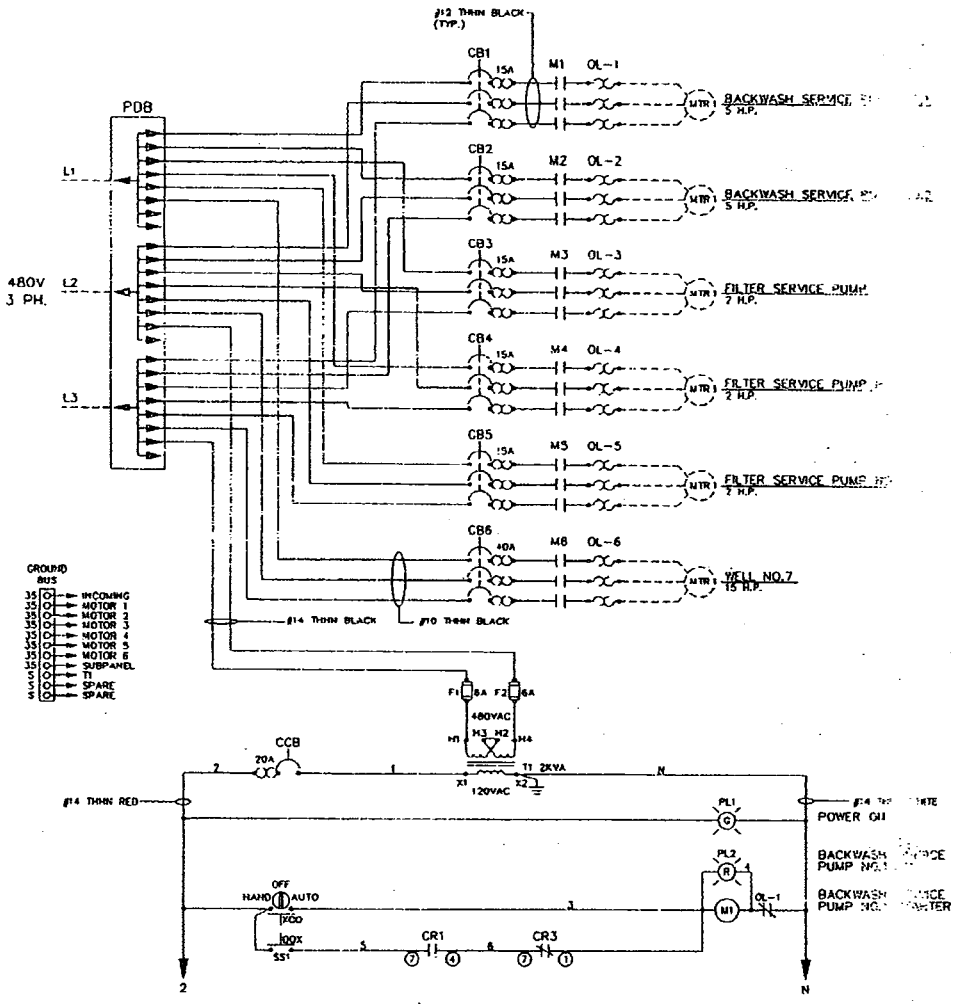
ATLANTIC FILTER

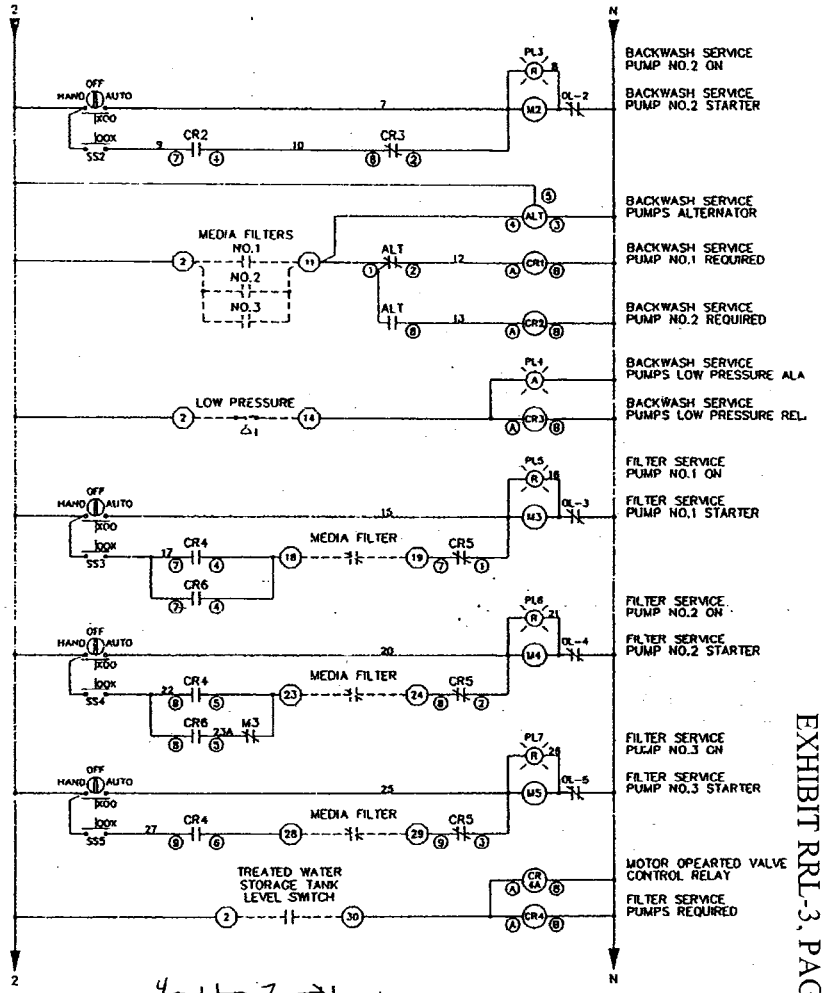
SYM.	CHANGE	BY	DATE

CAD REF.: A;J652PF-1

DRAWN BY/DATE: LG 12-18-91
CHECKED BY/DATE: CH 12-18-91
PROJECT: FP&L WATER TREATMENT SYSTEM MARTIN PLANT, UNITS 1 &
CUSTOMER: FLORIDA POWER AND LIGHT
SHEET 1 OF 3
JOB NO. J652

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4 7 1
5 8 2
6 9 3
control relays

NOTE:
ALL CONTROL WIRING WITHIN CONTROL CABINET TO BE #14 TFFN CU. UNLESS OTHERWISE NOTED
○ DESIGNATES TERMINALS FOR CUSTOMER CONNECTION
WIRE ENDS WITHIN CABINET TO BE IDENTIFIED WITH WIRE MARKERS.
ALL WIRES EXTERNAL TO CONTROL CABINET TO BE TERMINATED TO A TERMINAL

PUMP CONTROL PANEL
1-REQ'D

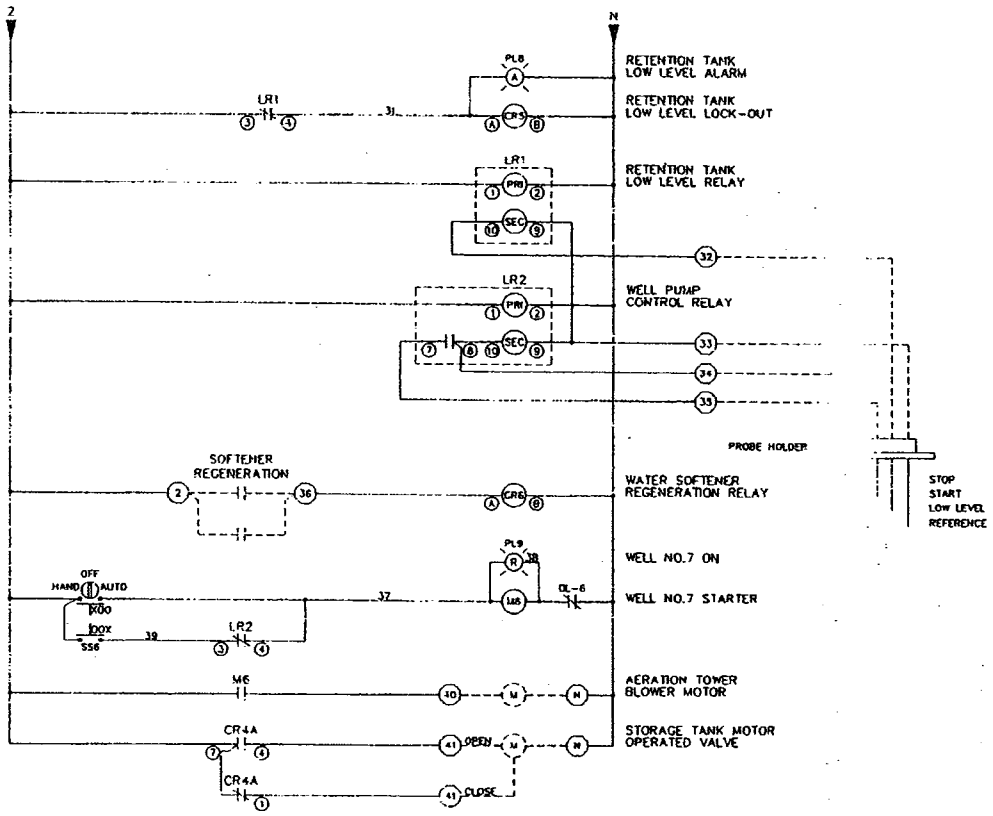
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CAD REF.: A:J652S-2			

ATLANTIC FILTER

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CHECKED BY/DATE: CH 12-18-91	CUSTOMER: FLORIDA POWER AND LIGHT
SHEET: 2 OF 3	JOB NO. J652

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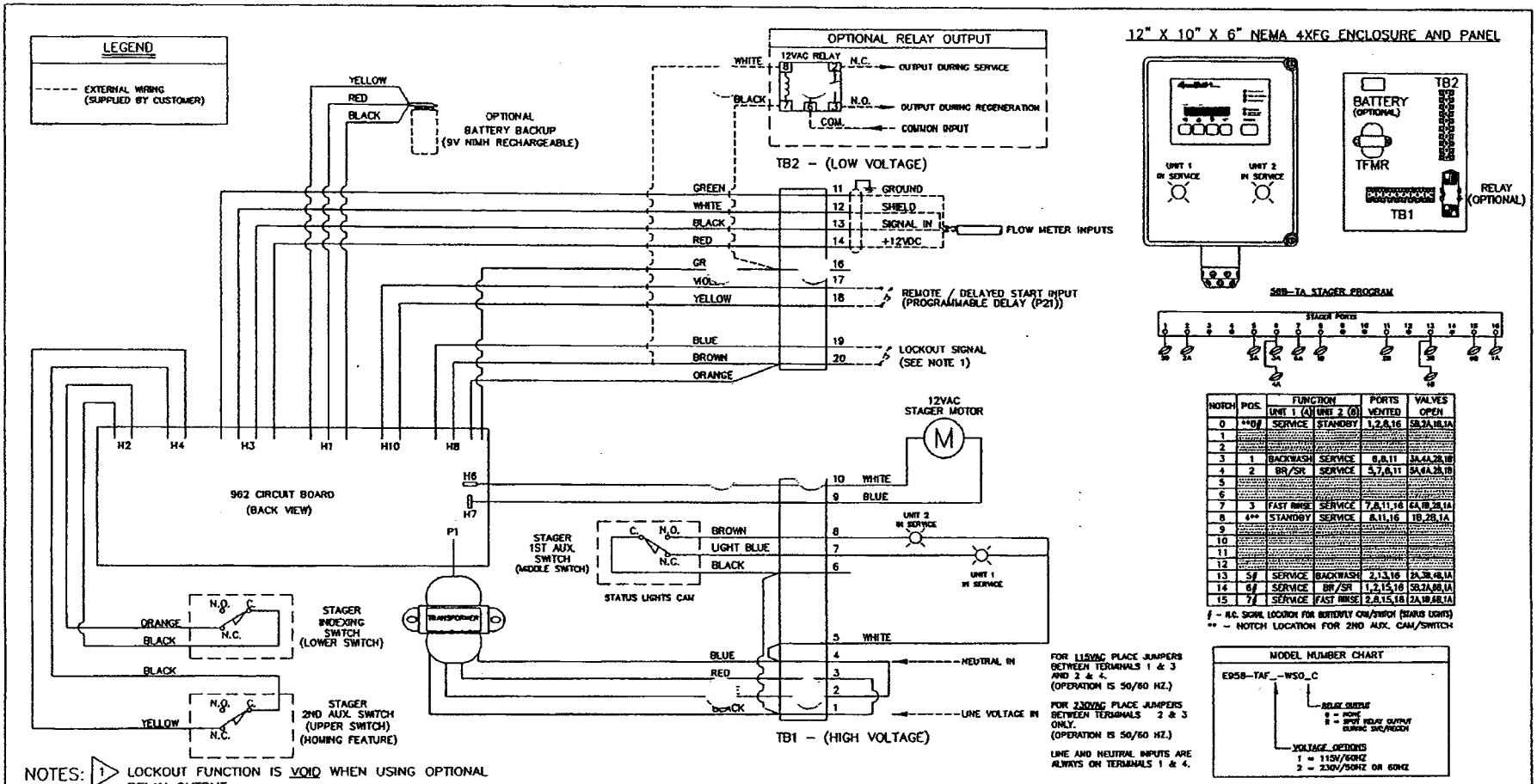
PUMP CONTROL PANEL

SYM.	CHANGE	BY	DATE
CAD REF.: A:J652S-3			

ATLANTIC FILTER

DRAWN BY/DATE: LG 12-18-91	PROJECT: FP&L WATER TREATMENT SYSTEM MARTIN PLANT, UNITS 1 & 2
CHECKED BY/DATE: CH 12-18-91	CUSTOMER: FLORIDA POWER AND LIGHT
	SHEET: 3 OF 3
	JOB NO.: J652

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NOTES: 1. LOCKOUT FUNCTION IS VOID WHEN USING OPTIONAL RELAY OUTPUT.

REV	DESCRIPTION	ECO	DWN	DATE	APVD
F	UPDATED STAGER REV	1259	MSM	04JUN01	
E	ADDED RELAY OPTION	1341	MSM	12SEP00	QLC 12SEP00
D	CHG WIRING FOR SW V1.2	1337	QLC	02AUG00	MSM 12SEP00
C	UPDATED MODEL No. CHART	NONE	RS	08 MAR00	QLC 09MAR00
B	1. CHANGED WIRE COLORS ON TERMINALS 5,7,8,17,18,19,20 2. CHANGED H+ TO BE WIRED THROUGH PROBING SWITCH.	NONE	QLC	18FEB00	QLC 18 FEB00
A	INITIAL RELEASE	NONE	QLC	17JAN00	MSM 17JAN00

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SCALE NONE — THIRD ANGLE — DO NOT SCALE

DWN BY	QLC	DATE	17 JAN 00
CHKD BY	VKP	DATE	01FEB00
APVD BY	MSM	DATE	01FEB00
APVD BY		DATE	

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APPENDIX B. CONSENT ORDER

Department of Environmental Protection

Jeb Bush
Governor

Southeast District
400 N. Congress Avenue, Suite 200
West Palm Beach, Florida 33401

Colleen M. Castille
Secretary

AUG 0 4 2006

CERTIFIED MAIL #7005 2570 0001 9601 9727
RETURN RECEIPT REQUESTED

Craig Arcari, General Manager
Florida Power & Light Company – Martin Plant
P.O. Box 176
Indiantown, Florida 34954

Re: DEP vs. Florida Power & Light Company
OGC File No. 06-0744/FPL Martin Plant PWS #4431748

Dear Mr. Arcari:

Enclosed for your review and signature is the Consent Order drafted by the Department in the above-styled case. The Consent Order represents the resolution acceptable to the Department in this matter. Please review, sign, and return the Consent Order to this office within 30 days of receipt for Department signature and distribution.

Thank you for your cooperation in this matter. If you have any questions concerning the Consent Order, please contact Michele Owens of this office at 561/681-6700.

Sincerely,

Kevin R. Neal 8/3/06
Kevin R. Neal Date
District Director
Southeast District

KRN/LAH/TRB/mo

Enclosure (all)

cc: Drinking Water Compliance Section – DEP/PSL

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION, Complainant, vs. FLORIDA POWER & LIGHT COMPANY, Respondent.	IN THE OFFICE OF THE SOUTHEAST DISTRICT OGC FILE NO. 06-0744

CONSENT ORDER

This Consent Order is entered into between the State of Florida Department of Environmental Protection ("Department") and Florida Power & Light Company ("Respondent") to reach settlement of certain matters at issue between the Department and Respondent.

The Department finds and the Respondent neither admits nor denies the following:

1. The Department is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources and to administer and enforce the provisions of the Florida Safe Drinking Water Act, Sections 403.850 et seq., Florida Statutes, and the rules promulgated thereunder, Title 62, Florida Administrative Code. The Department has jurisdiction over the matters addressed in this Consent Order.

2. Respondent is a "person" within the meaning of Section 403.852(5), Florida Statutes.

3. Respondent is the owner and is responsible for the operation of a nontransient noncommunity public water system ("System"), PWS #4431748, located on Warfield Boulevard, northwest of Indiantown, Martin County, Florida, which serves the Florida Power & Light Martin Power Plant.

4. The Department finds that Respondent is in violation of Rule 62-550.310(3), Fla. Admin. Code which establishes the maximum contaminant levels (MCLs) for total

trihalomethanes (TTHMs) and haloacetic acids (five) (HAA5s) as 0.080 milligrams per liter (mg/L) and 0.060 mg/L, respectively. The average results for samples collected from the System on March 15, 2005, April 12, 2005, September 14, 2005, and December 28, 2005, and analyzed for total trihalomethanes (TTHMs) and haloacetic acids (five) (HAA5s) are 0.173 milligrams per liter (mg/L) and 0.132 mg/L, respectively.

Having reached a resolution of the matter the Department and the Respondent mutually agree and it is

ORDERED:

5. Respondent shall comply with the following corrective actions within the stated time periods:

a. By September 1, 2006, Respondent shall retain the services of a Florida-registered professional engineer to evaluate the System and either submit an application, along with any required application fees, to the Department for a permit to construct any modifications needed to address the MCL exceedances, or, if the evaluation determines that no additional treatment is needed, a plan of corrective action ("Plan") with interim milestone dates, signed and sealed by a Florida-registered Professional Engineer.

b. The Department shall review the application/Plan submitted pursuant to paragraph 5.a. above. In the event additional information, modifications or specifications are necessary to process the application/Plan, the Department shall issue a written request for information ("RFI") to Respondent for such information. Respondent shall accordingly submit the requested information in writing to the Department within 30 days of receipt of the request. Respondent shall provide all information requested in any additional RFIs issued by the Department within 30 days of receipt of each request. Within 60 days of the date the Department receives the application/Plan pursuant to paragraph 5.a. above, Respondent shall provide all information necessary to complete the application/Plan. The Department shall notify Respondent in writing of Department approval of the Plan.

c. Within 180 days of issuance of any required permit(s), or written Department approval, if no permit is required, Respondent shall complete the Department-approved modifications in accordance with the permit/written approval issued pursuant to paragraphs 5.a. and 5.b. above, and submit to the Department the engineer's certification of completion of construction, along with all required supporting documentation. Respondent shall receive written Department clearance prior to placing the System modifications into service.

d. Respondent shall continue to sample quarterly for TTHMs and HAA5s. Results shall be submitted to the Department within ten (10) days of Respondent's receipt of the results.

e. In the event that the modifications approved by the Department pursuant to paragraphs 5.a. and b. are determined to be inadequate to resolve the MCL exceedances, the Department will notify the Respondent in writing. Within 30 days of receipt of written notification from the Department that the results of the quarterly sampling indicate that the System modifications have not resolved the violations, Respondent shall submit another proposal to address the MCL exceedances. Respondent shall provide all information requested in any RFIs issued by the Department within 30 days of receipt of each request. Within 60 days of the date the Department receives the application pursuant to this paragraph, Respondent shall provide all information necessary to complete the application.

f. Within two years of the effective date of this Consent Order, Respondent shall complete all corrective actions needed to resolve the MCL exceedances and submit written certification of completion to the Department for all modifications.

g. Respondent shall continue to issue public notice regarding the MCL exceedances every 90 days in accordance with Rule 62-560.410(1), Fla. Admin. Code, until the Department determines that System is in compliance with all MCLs. Respondent shall submit certification of delivery of public notice, using DEP Form 62-555.900(22), to the Department within ten days of issuing each public notice.

6. Within 30 days of the effective date of this Consent Order, Respondent shall reimburse the Department for costs and expenses in the amount of $500.00 which were incurred by the Department during the investigation of this matter and the preparation and tracking of this Consent Order. Payment shall 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."

7. Respondent agrees to pay the Department stipulated penalties in the amount of $100.00 per day for each and every day Respondent fails to timely comply with any of the requirements of paragraphs 5 and 6 of this Consent Order. A separate stipulated penalty shall be assessed for each violation of this Consent Order. Within 30 days of written demand from the Department, Respondent shall make payment of the appropriate stipulated penalties to "The Department of Environmental Protection" by cashier's check or money order and shall include the OGC number assigned to this Consent Order and the notation "Ecosystem Management and Restoration Trust Fund". Payment shall be sent to the Department of Environmental Protection, 400 North Congress Avenue, Suite 200, West Palm Beach, FL 33401. The Department may make demands for payment at any time after violations occur. Nothing in this paragraph shall prevent the Department from filing suit to specifically enforce any of the terms of this Consent Order. Any penalties assessed under this paragraph shall be in addition to the $500.00 agreed to in paragraph 6 of this Consent Order.

8. If any event, including administrative or judicial challenges by third parties unrelated to the Respondent, occurs which causes delay or the reasonable likelihood of delay, in complying with the requirements of this Consent Order, Respondent shall have the burden of proving the delay was or will be caused by circumstances beyond the reasonable control of the Respondent and could not have been or cannot be overcome by Respondent's due diligence. Economic circumstances shall not be considered circumstances beyond the control of Respondent, nor shall the failure of a contractor, subcontractor, materialman or other agent

(collectively referred to as "contractor") to whom responsibility for performance is delegated to meet contractually imposed deadlines be a cause beyond the control of Respondent, unless the cause of the contractor's late performance was also beyond the contractor's control. Upon occurrence of an event causing delay, or upon becoming aware of a potential for delay, Respondent shall notify the Department's Southeast District Office in West Palm Beach orally within 72 hours or within three working days and shall, within ten calendar days of oral notification to the Department, notify the Department in writing of the anticipated length and cause of the delay, the measures taken or to be taken to prevent or minimize the delay and the timetable by which Respondent intends to implement these measures. If the parties can agree that the delay or anticipated delay has been or will be caused by circumstances beyond the reasonable control of Respondent, the time for performance of one or more of the requirements hereunder shall be extended for a period equal to the agreed delay resulting from such circumstances. Such agreement shall adopt all reasonable measures necessary to avoid or minimize delay. Failure of Respondent to comply with the notice requirements of this Paragraph in a timely manner shall constitute a waiver of Respondent's right to request an extension of time for compliance with the requirements of this Consent Order.

9. Persons who are not parties to this Consent Order, but whose substantial interests are affected by this Consent Order, have a right, pursuant to Sections 120.569 and 120.57, Florida Statutes, to petition for an administrative hearing on it. The Petition must contain the information set forth below and must be filed (received) at the Department's Office of General Counsel, 3900 Commonwealth Boulevard, MS# 35, Tallahassee, Florida 32399-3000 within 21 days of receipt of this notice. A copy of the Petition must also be mailed at the time of filing to the District Office named above at the address indicated. Failure to file a petition within the 21 days constitutes a waiver of any right such person has to an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes.

10. The petition shall contain the following information:

a. The name, address, and telephone number of each petitioner; the Department's Consent Order identification number and the county in which the subject matter or activity is located;

b. A statement of how and when each petitioner received notice of the Consent Order;

c. A statement of how each petitioner's substantial interests are affected by the Consent Order;

d. A statement of the material facts disputed by petitioner, if any;

e. A statement of facts which petitioner contends warrant reversal or modification of the Consent Order;

f. A statement of which rules or statutes petitioner contends require reversal or modification of the Consent Order;

g. A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Consent Order.

11. If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this Notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the subject Consent Order have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 21 days of receipt of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Sections 120.569 and 120.57, Florida Statutes, and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-106.205, Florida Administrative Code.

12. A person whose substantial interests are affected by the Consent Order may file a timely petition for an administrative hearing under Sections 120.569 and 120.57, Florida

Statutes, or may choose to pursue mediation as an alternative remedy under Section 120.573, Florida Statutes, before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for pursuing mediation are set forth below.

13. Mediation may only take place if the Department and all the parties to the proceeding agree that mediation is appropriate. A person may pursue mediation by reaching a mediation agreement with all parties to the proceeding (which include the Respondent, the Department, and any person who has filed a timely and sufficient petition for a hearing) and by showing how the substantial interests of each mediating party are affected by the Consent Order. The agreement must be filed in (received by) the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, MS #35, Tallahassee, Florida 32399-3000, within 10 days after the deadline as set forth above for the filing of a petition.

14. The agreement to mediate must include the following:

a. The names, addresses, and telephone numbers of any persons who may attend the mediation;

b. The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time;

c. The agreed allocation of the costs and fees associated with the mediation;

d. The agreement of the parties on the confidentiality of discussions and documents introduced during mediation;

e. The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen;

f. The name of each party's representative who shall have authority to settle or recommend settlement;

g. Either an explanation of how the substantial interests of each mediating party will be affected by the action or proposed action addressed in this notice of intent or a

statement clearly identifying the petition for hearing that each party has already filed, and incorporating it by reference; and

h. The signatures of all parties or their authorized representatives. As provided in Section 120.573, Florida Statutes, the timely agreement of all parties to mediate will toll the time limitations imposed by Sections 120.569 and 120.57, Florida Statutes, for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such a modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above, and must therefore file their petitions within 21 days of receipt of this notice. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57, Florida Statutes, remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

15. Respondent shall allow all authorized representatives of the Department access to the facility at reasonable times for the purpose of determining compliance with the terms of this Consent Order and the rules and statutes of the Department.

16. All submittals and payments required by this Consent Order to be submitted to the Department shall be sent to the Florida Department of Environmental Protection, Southeast District Water Facilities Program, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida, 33401.

17. This Consent Order is a settlement of the Department's civil and administrative authority arising under Florida law to resolve the matters addressed herein. This Consent Order is not a settlement of any criminal liabilities, which may arise under Florida law, nor is it a

settlement of any violation which may be prosecuted criminally or civilly under federal law and which Respondent may defend.

18. The Department hereby expressly reserves the right to initiate appropriate legal action to prevent or prohibit any violations arising after the date of this Consent Order of applicable statutes, or the rules promulgated thereunder that are not specifically addressed by the terms of this Consent Order.

19. The terms and conditions set forth in this Consent Order may be enforced in a court of competent jurisdiction pursuant to Sections 120.69 and 403.121, Florida Statutes. Failure to comply with the terms of this Consent Order shall constitute a violation of Section 403.859, Florida Statutes.

20. The Department, for and in consideration of the complete and timely performance by Respondent of the obligations agreed to in this Consent Order, hereby waives its right to seek judicial imposition of damages or civil penalties for alleged violations.

21. Respondent is fully aware that a violation of the terms of this Consent Order may subject Respondent to judicial imposition of damages, civil penalties up to $5,000.00 per day per violation, and criminal penalties, except as limited by the provisions of this Consent Order.

22. Except as otherwise provided herein, entry of this Consent Order does not relieve Respondent of the need to comply with applicable federal, state or local laws, regulations or ordinances.

23. No modifications of the terms of this Consent Order shall be effective until reduced to writing and executed by both Respondent and the Department.

24. Respondent acknowledges and waives its right to an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes, on the terms of this Consent Order. Respondent acknowledges its right to appeal the terms of this Consent Order pursuant to Section 120.68, Florida Statutes, and waives that right upon signing this Consent Order.

25. This Consent Order is a final order of the Department pursuant to Section 120.52(7), Florida Statutes, and it is final and effective on the date filed with the Clerk of the

Department unless a Petition for Administrative Hearing is filed in accordance with Chapter 120, Florida Statutes. Upon the timely filing of a petition this Consent Order will not be effective until further order of the Department.

FOR THE RESPONDENT:

_____

Craig Arcari, General Manager Date
Florida Power & Light Company - Martin Plant
P.O. Box 176
Indiantown, Florida 34954

DONE AND ORDERED this ___ day of _____, 200_, in West Palm Beach, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

_____

Kevin R. Neal Date
District Director
Southeast District

FILED, on this date, pursuant to §120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

_____ _____

Clerk **Date**

Copies furnished to:
Lea Crandall, Agency Clerk, MS 35
Drinking Water Compliance Section, FDEP/PSL

APPENDIX C. CALCULATIONS

Golder Associates

SUBJECT	DBP Water Quality Data		
Job No. 063-3495	Made by NAR	Date 8/16/06	
Ref. Calc 001	Checked SWM	Sheet 1 of 1	
	Reviewed MD		

Received Tabulated Data from Willie Welch & Stan McElroy during site visit (attached)

Data were input to spreadsheet data.xls, and results shown on Exhibits 1-4

Conclusion:

The Total Tri-halomethane problem is caused primarily by the presence of Chloroform

The Total Halo-acetic acid problem is caused by two compounds: Di- and Tri-chloroacetic acid

Location	Potable POE	MRT	MRT	MRT	MRT	MRT	MRT
Date	8/25/2004	5/25/2006	2/13/2006	12/21/2005	9/14/2005	4/12/2005	3/15/2005
Monochloroacetic acid - ug/L	5.3	U	2.8	4	4.7	4.9	U
Dichloroacetic acid - ug/L	120	46.4	59	54	100	87	33
Trichloroacetic acid - ug/L	100	50.9	41	43	99	64	29
Monobromoacetic acid - ug/L	U	U	0.46	0.3	0.5	U	U
Dibromoacetic acid - ug/L	1.3	U	2.6	1.2	0.52	0.8	0.47
HAA5 - ug/L	230	97.3	105	100	210	160	63
HAAF Standard - ug/L	60	60	60	60	60	60	60
Chloroform - ug/L	250	123	160	140	210	160	70
Bromoform - ug/L	U	U	U	U	U	U	U
Bromodichloromethane - ug/L	37	27.5	46	23	32	32	13
Dibromochloromethane - ug/L	3.9	5.02	11	2.5	3.3	3.7	1.4
TTHM - ug/L	290	155	210	160	240	190	84
TTHM Standard - ug/L	80	80	80	80	80	80	80
Chlorine residual			0.6	1.2	0.4	0.4	1.1

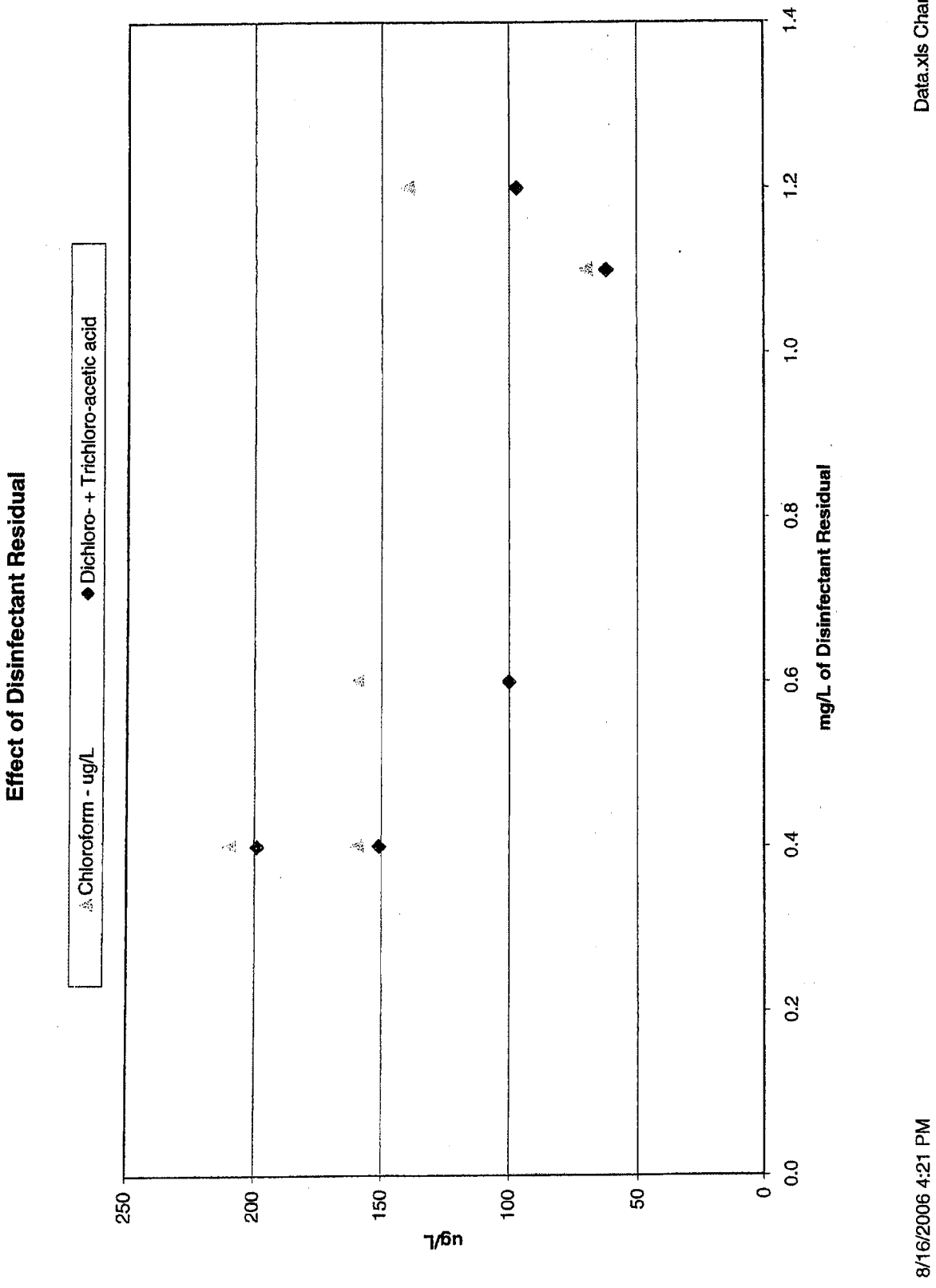
Cable 1
Exh 1

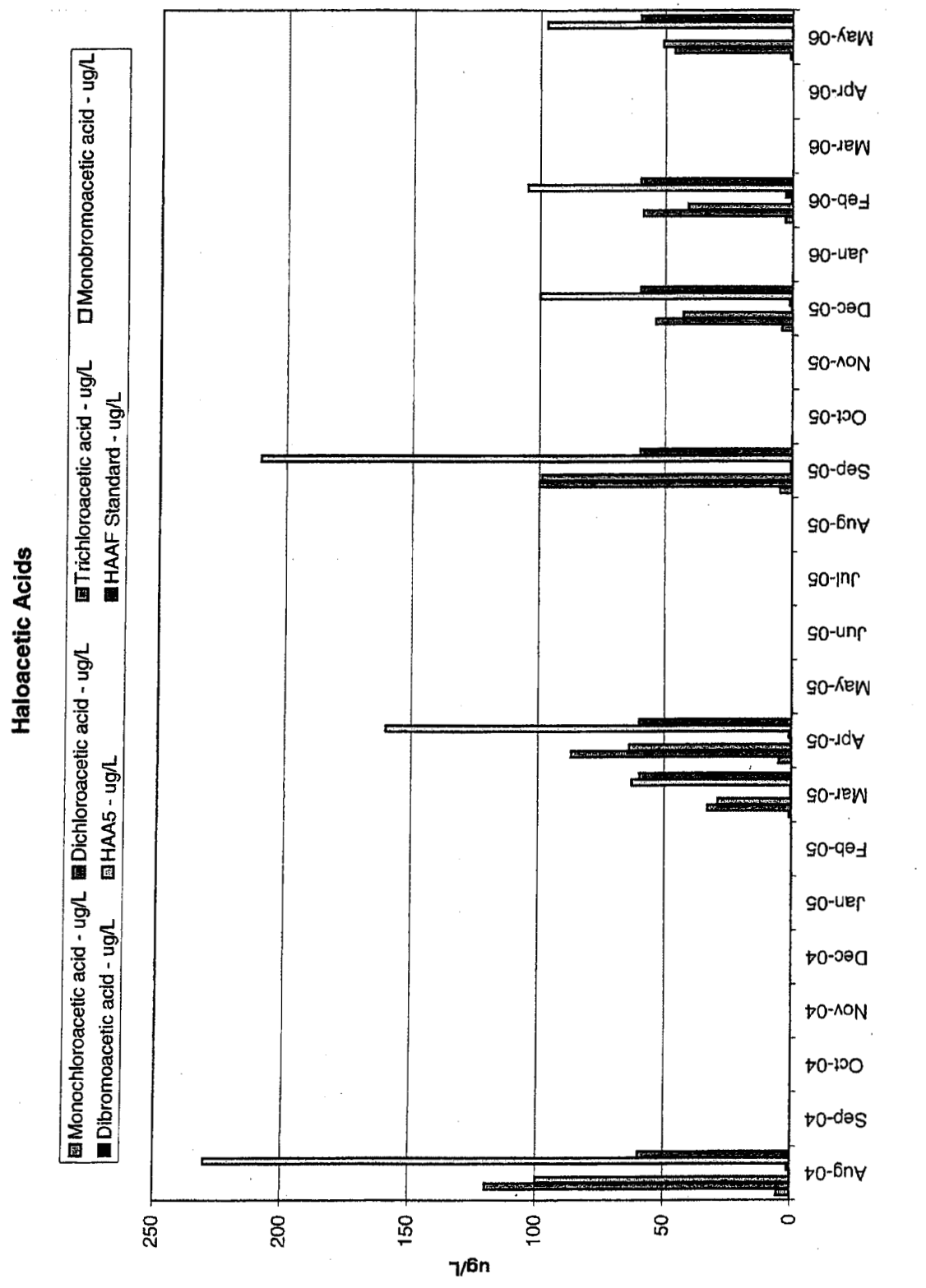
8/16/2006 4:11 PM

Data.xls Chart2

DOCKET NO. 070007-EI
GOLDER ASSOCIATES, INC.
EXHIBIT RRL-3, PAGE 41 OF 107

GLC 1 EXH 3


Effect of Disinfectant Residual
Chloroform - ug/L
Dichloro- + Trichloro-acetic acid
ug/L
250
200
150
100
50
0
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
mg/L of Disinfectant Residual
Data.xls Chart3
8/16/2006 4:21 PM



Data.xls Chart1

8/16/2006 3:59 PM

Jupiter
Environmental Laboratories, Inc.

Jupiter Environmental Laboratories, Inc.
150 S. Old Dixie Highway
Jupiter, FL 33458
Phone: (561)575-0030
Fax: (561)575-4118

ANALYTICAL RESULTS

LOG# 616076
Project ID: Q.I. Analysis

Lab ID: 616076004 Date Received: 5/25/2006 Matrix: Aqueous Liquid
Sample ID: 3/4 Lab MRT Date Collected: 5/24/2006

Parameters	Results	Units	Report Limit	MDL	DF	Prepared	By	Analyzed	By	Qual	CAS
Analysis Desc: EPA 524.2 Scan by			Preparation Method: NONE Analytical Method: EPA 524.2								
Chloroform	0.123	mg/L	0.00100		1	05/26/06	ESC	05/29/06	ESC		
Bromodichloromethane	0.0275	mg/L	0.00100		1	05/26/06	ESC	05/29/06	ESC		
Chlorodibromomethane	0.00502	mg/L	0.00100		1	05/26/06	ESC	05/29/06	ESC		
Bromoform	U	mg/L	0.00100		1	05/26/06	ESC	05/29/06	ESC		
Total Trihalomethanes	0.155	mg/L	0.00100		1	05/26/06	ESC	05/29/06	ESC		
Analysis Desc EPA 552.2											
Bromoacetic acid	U	mg/L	0.00200		1	05/26/06	ESC	05/29/06	ESC		
Chloroacetic acid	U	mg/L	0.00200		1	05/26/06	ESC	05/29/06	ESC		
Dibromoacetic acid	U	mg/L	0.00200		1	05/26/06	ESC	05/29/06	ESC		
Dichloroacetic acid	0.0464	mg/L	0.00200		1	05/26/06	ESC	05/29/06	ESC		
Trichloroacetic acid	0.0509	mg/L	0.00200		1	05/26/06	ESC	05/29/06	ESC		
Total Haloacetic acids	0.0973	mg/L	0.00200		1	05/26/06	ESC	05/29/06	ESC		

FDOH# E86546

CERTIFICATE OF ANALYSIS

This report shall not be reproduced, except in full,
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Jupiter
Environmental Laboratories, Inc.

Jupiter Environmental Laboratories, Inc.
150 S. Old Dixie Highway
Jupiter, FL 33458
Phone: (561)575-0030
Fax: (561)575-4116

ANALYTICAL RESULTS QUALIFIERS

LOG# 616076
Project ID: Q.I. Analysis

PARAMETER QUALIFIERS

SUBCONTRACTOR NELAC CERTIFICATION

616076 ESC = E87487

FDOH# E86548

CERTIFICATE OF ANALYSIS

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Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

PUBLIC WATER SYSTEM INFORMATION (to be completed by sampler - Please type or print legibly)

System Name: FPL - INDIANTOWN PWS I.D. #: 4 4 3 1 7 4 8

System Type (check one) ☐ Community ☒ Nontransient Noncommunity ☐ Transient Noncommunity

Address: 21960 SW WARFIELD BLVD.

City: INDIANTOWN State: FL. ZIP Code: 34956

Phone #: 772-597-7211 Fax #: 772-597-7416

E-Mail Address:

SAMPLE INFORMATION (to be completed by sampler)

Sample Number: 001 Location Code (if known): MRT

Sample Date: 02/13/06 Sample Time: 3:00 PM

Sample Location (be specific): 3/4 Lab MRT Grab

Disinfectant Residual (Required when reporting results for trihalomethanes and haloacetic acids): .60 mg/L Field pH:

Sample Type (Check Only One)

- ☐ Distribution
- ☐ Entry Point (to Distribution)
- ☐ Plant Tap not for compliance with 62-550)
- ☐ Raw (at well or intake)
- ☒ Max Residence Time
- ☐ Ave Residence Time
- ☐ Near First Customer

Reason(s) for Sample (Check all that apply)

- ☐ Routine Compliance (with 62-550)
- ☐ Confirmation of MCL Exceedence*
- ☐ Composite of Multiple Sites**
- ☐ Clearance (permitting)
- ☐ Other:
- ☒ Quarterly (Which Qtr? 1-SI
- ☐ Special (not for compliance with 62-550)
- ☐ Violation Resolution
- ☐ Replacement (of Invalidated Sample)

Sampling Procedure Used or Other Comments:

*See 62-550.500(6) for requirements and restrictions.
Note: See 62-550.512(3) for additional requirements for Nitrate or Nitrite MCL exceedences.

** See 62-550.550(4) for requirements and attach a results page for each site.

Sampler's Name: STAN MCELROY

Sampler's Phone #: 772-597-7640 Sampler's Fax #: 772-597-7416

Sampler's E-Mail Address: STAN.J.MCELROY@FPL.COM

CERTIFICATION (to be completed by sampler)

I, STAN MCELROY (Print Name), SR. PLT. TECH - LEAD OP. (Print Title)

do HEREBY CERTIFY that the above public water system and sample collection information is completed and correct.

Signature: S. J. McElroy Date: 4-10-06

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

LABORATORY CERTIFICATION INFORMATION (to be completed by lab - Please type or print legibly)

ATTACH A CURRENT DOH ANALYTE SHEET

Lab Name: Harbor Branch Environmental Laboratories, Inc. Florida Certification #: E96080

Address: 5600 US 1 North Certification Expiration Date: 06/30/2006

Fort Pierce, FL 34946 Phone #: (772) 465-2400 Ext. 285

ANALYSIS INFORMATION (to be completed by lab) Date Sample(s) Received:: 2/14/06

PWS ID (From Page 1): 443-1748 Sample Number (From Page 1): 001

Lab Assigned Report Number or Job ID: 2023804001

Group(s) Analyzed and Results attached for compliance with Chapter 62-550, F.A.C. (Check all that apply):

Inorganics	Synthetic Organics	Volatile Organics	Disinfection Byproducts
☐ All 17	☐ All 30	☐ All 21	☑ Trihalomethanes
☐ Partial	☐ All Except Dioxin	☐ Partial	☑ Haloacetic Acids
☐ Nitrate	☐ Partial		☐ Bromate
☐ Nitrite	☐ Dioxin Only	Radionuclides	☐ Chlorite
☐ Asbestos Only		☐ Single Sample	
		☐ Qtrly Composite**	Secondaries
			☐ All 14
			☐ Partial

Were any analyses subcontracted? ___ Yes X No

If yes, please provide DOH certification numbers: _____

ATTACH DOH ANALYTE SHEET FOR EACH SUBCONTRACTED LAB

CERTIFICATION

I, Cindy Cromer (Print Name), Laboratory Director (Print Title)

do HEREBY CERTIFY that all attached analytical data are correct and unless noted meet all requirements of the National Environmental Laboratory Accreditation Conference (NELAC).

Signature Cindy Cromer Date: 06-Mar-06

* Failure to provide a valid and current Florida DOH lab certification number and a current Analyte Sheet for the attached analysis results will result in rejection of the report, possible enforcement against the public water system for failure to sample, and may result in notification of the DOH Bureau of Laboratory Services.

** Please provide radiological sample dates locations for each quarter.

COMPLIANCE DETERMINATION (to be completed by DEP or DOH)

Sample Collection Info Satisfactory: ☐ Yes ☐ No Sample Analysis Info Satisfactory: ☐ Yes ☐ No

☐ Replacement Sample(s) Requested (circle or highlight group(s) above) ☐ Revised Report Requested (circle or highlight group(s) above)

☐ Additional Monitoring Required (circle or highlight group(s) above)

Reason(s): ☐ MCL(s) Exceeded ☐ Detection(s) ☐ Incomplete Report
☐ Missing Analyte Sheet(s) ☐ Location Unsatisfactory ☐ Analysis Unsatisfactory
☐ Other: _____

Person Notified: _____ Date Notified: _____

Comments: _____

Date Reviewed: _____ DEP/DOH Reviewing Official: _____

HARBOR BRANCH
ENVIRONMENTAL
LABORATORIES, INC.
600 U.S. 1 North, Fort Pierce FL 34946
Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

DISINFECTION BYPRODUCTS ANALYSES

62-550.310(3)

Client: Florida Power & Light
Report Number/ Job ID Martin Plant DW THM/HAA5
Sample Location: 3/4 Lab MRT Grab
Disinfectant Residual (mg/L .60
Sample Number: 2023804001
PWS ID 4431748
Sampling Date: 2/13/06 15:00
Date Received: 2/14/06 12:35

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2450	Monochloroacetic Acid	[N/A]	ug/L	2.8		EPA 552.1	0.88	2/21/06	10:11 PM	E96080
2451	Dichloroacetic Acid	[N/A]	ug/L	59		EPA 552.1	1.3	2/23/06	6:46 AM	E96080
2452	Trichloroacetic acid	[N/A]	ug/L	41		EPA 552.1	0.39	2/23/06	6:46 AM	E96080
2453	Monobromoacetic Acid	[N/A]	ug/L	0.46		EPA 552.1	0.28	2/21/06	10:11 PM	E96080
2454	Dibromoacetic Acid	[N/A]	ug/L	2.6		EPA 552.1	0.18	2/21/06	10:11 PM	E96080
2456	Total Haloacetic Acids (HAA5)	[60]	ug/L							
2941	Chloroform	[N/A]	ug/L	160		EPA 524.2	2.5	2/27/06	11:15 AM	E96080
2942	Bromoform	[N/A]	ug/L	0.41 U		EPA 524.2	0.41	2/22/06	5:18 PM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	46		EPA 524.2	0.25	2/22/06	5:18 PM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	11		EPA 524.2	0.30	2/22/06	5:18 PM	E96080
2950	Total Trihalomethanes	[80]	ug/L							

NOTE: Do not round values. Report results to the accuracy, precision, and sensitivity of the analytical method used. Totals for haloacetic acids and total trihalomethanes will be calculated by DEP or DOH.

Reporting Format 62-550 730
Effective January 1995, Revised January 2004

Results must be reported with appropriate qualifiers in accordance with Florida Administrative Code Rule 62-160, Table 1. Results Qualified with A, F, H, N, O, T, Z, ?, *, are unacceptable for compliance with 62-550. Results qualified with a J, Q, R, or Y must be accompanied by written justification and will be evaluated on a case by case basis. To avoid a monitoring violation, unacceptable results must be replaced with acceptable results from samples collected during the same monitoring peri

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Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

CERTIFICATE OF ANALYSIS

[2023804]

Client: Florida Power & Light *Workorder ID:* Martin Plant DW THM/HAA5

Parameter	Qualifier	Result[1]	Units	Reporting Limit	Method	Laboratory Batch	Prep Date/Time	Analyzed Date/Time	Analyst	Lab ID
Laboratory ID: **2023804001** *Sample ID:* **3/4 Lab MRT Grab**					*Sampled: 02/13/06 15:00* *Matrix: Water*		*Received: 02/14/06 12:35* Results reported on Wet Weight Basis			
Bromodichloromethane		**46**	ug/L	0.25	EPA 524.2	VOC2600		02/22/06 17:18	WR	E96080
Bromoform		**0.41 U**	ug/L	0.41	EPA 524.2	VOC2600		02/22/06 17:18	WR	E96080
Chloroform		**160**	ug/L	2.5	EPA 524.2	VOC2600		02/27/06 11:15	WR	E96080
Dibromochloromethane		**11**	ug/L	0.30	EPA 524.2	VOC2600		02/22/06 17:18	WR	E96080
Total THMs		**210**	ug/L	0.50	EPA 524.2	VOC2600		02/22/06 17:18	WR	E96080
Dibromoacetic Acid		**2.6**	ug/L	0.18	EPA 552.1	PEST4659	02/22/06 15:27	02/21/06 22:11	RS	E96080
Dichloroacetic Acid		**59**	ug/L	1.3	EPA 552.1	PEST4659	02/22/06 15:27	02/23/06 6:46	RS	E96080
Monobromoacetic Acid		**0.46**	ug/L	0.28	EPA 552.1	PEST4659	02/22/06 15:27	02/21/06 22:11	RS	E96080
Monochloroacetic Acid		**2.8**	ug/L	0.88	EPA 552.1	PEST4659	02/22/06 15:27	02/21/06 22:11	RS	E96080
Total HAAs		**100**	ug/L	0.37	EPA 552.1	PEST4659	02/22/06 15:27	02/23/06 6:46	RS	E96080
Total HAAs		**110**	ug/L	0.18	EPA 552.1	PEST4659	02/22/06 15:27	02/21/06 22:11	RS	E96080
Trichloroacetic acid		**41**	ug/L	0.39	EPA 552.1	PEST4659	02/22/06 15:27	02/23/06 6:46	RS	E96080
Laboratory ID: **2023804002** *Sample ID:* **Trip Blank**					*Sampled: 02/13/06 0:00* *Matrix: Water*		*Received: 02/14/06 12:35* Results reported on Wet Weight Basis			
Bromodichloromethane		**0.25 U**	ug/L	0.25	EPA 524.2	VOC2600		02/22/06 17:51	WR	E96080
Bromoform		**0.41 U**	ug/L	0.41	EPA 524.2	VOC2600		02/22/06 17:51	WR	E96080
Chloroform		**0.25 U**	ug/L	0.25	EPA 524.2	VOC2600		02/22/06 17:51	WR	E96080
Dibromochloromethane		**0.30 U**	ug/L	0.30	EPA 524.2	VOC2600		02/22/06 17:51	WR	E96080
Total THMs		**0.50 U**	ug/L	0.50	EPA 524.2	VOC2600		02/22/06 17:51	WR	E96080

[1]Result Qualifiers: U = Not Detected I = Analyte detected between the Laboratory Method Detection Limit and Laboratory Reporting Limit
Applicable Florida Department of Environmental Protection Qualifiers defined below. Statement of Estimated Uncertainty available upon request.

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

PUBLIC WATER SYSTEM INFORMATION (to be completed by sampler - Please type or print legibly)

System Name: FPL MARTIN PLANT PWS I.D. #: 4 4 3 1 7 4 8

System Type (check one) ☐ Community ☒ Nontransient Noncommunity ☐ Transient Noncommunity

Address: 21900 SW WARFIELD BLVD.

City: INDIANTOWN State: FL ZIP Code: 34956

Phone #: 772-597-7211 Fax #: 772-597-7416

E-Mail Address:

SAMPLE INFORMATION (to be completed by sampler)

Sample Number: PMR 122805 Location Code (if known):

Sample Date: 12/21/05 Sample Time: 8:00 AM

Sample Location (be specific): 3/4 Lab MRT Grab

Disinfectant Residual (Required when reporting results for trihalomethanes and haloacetic acids): 1.2 mg/L Field pH:

Sample Type (Check Only One)

- ☐ Distribution
- ☐ Entry Point (to Distribution)
- ☐ Plant Tap not for compliance with 62-550)
- ☐ Raw (at well or intake)
- ☒ Max Residence Time
- ☐ Ave Residence Time
- ☐ Near First Customer

Reason(s) for Sample (Check all that apply)

- ☐ Routine Compliance (with 62-550)
- ☐ Confirmation of MCL Exceedence*
- ☐ Composite of Multiple Sites**
- ☐ Clearance (permitting)
- ☐ Other:
- ☒ Quarterly (Which Qtr? 4TH)
- ☐ Special (not for compliance with 62-550)
- ☐ Violation Resolution
- ☐ Replacement (of Invalidated Sample)

Sampling Procedure Used or Other Comments:

*See 62-550.500(6) for requirements and restrictions. Note: See 62-550.512(3) for additional requirements for Nitrate or Nitrite MCL exceedences.

** See 62-550.550(4) for requirements and attach a results page for each site.

Sampler's Name: STAN MCELROY

Sampler's Phone #: 772-597-7640 Sampler's Fax #: 772-597-7416

Sampler's E-Mail Address:

CERTIFICATION (to be completed by sampler)

I, STAN MCELROY (Print Name), LEAD OP. (Print Title)

do HEREBY CERTIFY that the above public water system and sample collection information is completed and correct.

Signature: S. J. McElroy Date: 1-09-06

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

LABORATORY CERTIFICATION INFORMATION (to be completed by lab - Please type or print legibly)

ATTACH A CURRENT DOH ANALYTE SHEET

Lab Name: Harbor Branch Environmental Laboratories, Inc. Florida Certification #: E96080

Address: 5600 US 1 North Certification Expiration Date: 06/30/2006

Fort Pierce, FL 34946 Phone #: (772) 465-2400 Ext. 285

ANALYSIS INFORMATION (to be completed by lab) Date Sample(s) Received:: 12/21/05

PWS ID (From Page 1): 4431748 Sample Number (From Page 1): _____

Lab Assigned Report Number or Job ID: 2023325001

Group(s) Analyzed and Results attached for compliance with Chapter 62-550, F.A.C. (Check all that apply):

Inorganics	Synthetic Organics	Volatile Organics	Disinfection Byproducts
☐ All 17	☐ All 30	☐ All 21	☒ Trihalomethanes
☐ Partial	☐ All Except Dioxin	☐ Partial	☒ Haloacetic Acids
☐ Nitrate	☐ Partial		☐ Bromate
☐ Nitrite	☐ Dioxin Only	Radionuclides	☐ Chlorite
☐ Asbestos Only		☐ Single Sample	
		☐ Qtrly Composite**	Secondaries
			☐ All 14
			☐ Partial

Were any analyses subcontracted? ___ Yes _X_ No

If yes, please provide DOH certification numbers: _____

ATTACH DOH ANALYTE SHEET FOR EACH SUBCONTRACTED LAB

CERTIFICATION

I, Cindy Cromer (Print Name), Laboratory Director (Print Title)

do HEREBY CERTIFY that all attached analytical data are correct and unless noted meet all requirements of the National Environmental Laboratory Accreditation Conference (NELAC).

Signature Cindy Cromer Date: 05-Jan-06

* Failure to provide a valid and current Florida DOH lab certification number and a current Analyte Sheet for the attached analysis results will result in rejection of the report, possible enforcement against the public water system for failure to sample, and may result in notification of the DOH Bureau of Laboratory Services.

** Please provide radiological sample dates /locations for each quarter.

COMPLIANCE DETERMINATION (to be completed by DEP or DOH)

Sample Collection Info Satisfactory: ☐ Yes ☐ No Sample Analysis Info Satisfactory: ☐ Yes ☐ No

☐ Replacement Sample(s) Requested (circle or highlight group(s) above) ☐ Revised Report Requested (circle or highlight group(s) above)

☐ Additional Monitoring Required (circle or highlight group(s) above)

Reason(s): ☐ MCL(s) Exceeded ☐ Detection(s) ☐ Incomplete Report
☐ Missing Analyte Sheet(s) ☐ Location Unsatisfactory ☐ Analysis Unsatisfactory
☐ Other: _____

Person Notified: _____ Date Notified: _____

Comments: _____

Date Reviewed: _____ DEP/DOH Reviewing Official: _____

HARBOR BRANCH
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5600 U.S. 1 North, Fort Pierce FL 34946
Phone (772) 465-2400, Ext. 285 Fax: (772) 467-1584

CERTIFICATE OF ANALYSIS

[2023325]

Client: Florida Power & Light *Workorder ID:* Martin Plant DW THM/HAA5

Parameter	Qualifier	Result[1]	Units	Reporting Limit	Method	Laboratory Batch	Prep Date/Time	Analyzed Date/Time	Analyst	Lab ID
Laboratory ID: **2023325001**					*Sampled:* 12/21/05 8:00		*Received:* 12/21/05 12:50			
Sample ID: **3/4 Lab MRT Grab**					*Matrix:* Water		Results reported on Wet Weight Basis			
Bromodichloromethane		23	ug/L	0.25	EPA 524.2	VOC2576		12/28/05 3:28	WR	E96080
Bromoform		0.41 U	ug/L	0.41	EPA 524.2	VOC2576		12/28/05 3:28	WR	E96080
Chloroform		140	ug/L	2.5	EPA 524.2	VOC2576		12/28/05 9:33	WR	E96080
Dibromochloromethane		2.5	ug/L	0.30	EPA 524.2	VOC2576		12/28/05 3:28	WR	E96080
Total THMs		160	ug/L	0.50	EPA 524.2	VOC2576		12/28/05 3:28	WR	E96080
Dibromoacetic Acid		1.2	ug/L	0.18	EPA 552.1	PEST4626	01/2/06 7:41	01/2/06 18:58	RS	E96080
Dichloroacetic Acid		54	ug/L	0.66	EPA 552.1	PEST4626	01/2/06 7:41	01/2/06 18:58	RS	E96080
Monobromoacetic Acid		0.30	ug/L	0.28	EPA 552.1	PEST4626	01/2/06 7:41	01/2/06 18:58	RS	E96080
Monochloroacetic Acid		4.0	ug/L	0.88	EPA 552.1	PEST4626	01/2/06 7:41	01/2/06 18:58	RS	E96080
Total HAAs		100	ug/L	0.18	EPA 552.1	PEST4626	01/2/06 7:41	01/2/06 18:58	RS	E96080
Trichloroacetic acid		43	ug/L	0.98	EPA 552.1	PEST4626	01/2/06 7:41	01/3/06 10:31	RS	E96080

[1]Result Qualifiers: U = Not Detected I = Analyte detected between the Laboratory Method Detection Limit and Laboratory Reporting Limit
Applicable Florida Department of Environmental Protection Qualifiers defined below. Statement of Estimated Uncertainty available upon request.

HARBOR BRANCH
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DISINFECTION BYPRODUCTS ANALYSES
62-550.310(3)

Client:	Florida Power & Light	Report Number/ Job ID	Martin Plant DW THM/HAA5
Sample Location:	3/4 Lab MRT Grab	Disinfectant Residual (mg/L	1.2
Sample Number:	2023325001	PWS ID	4431748
Sampling Date:	12/21/05 8:00		
Date Received:	12/21/05 12:50		

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2450	Monochloroacetic Acid	[N/A]	ug/L	**4.0**		EPA 552.1	0.88	1/02/06	6:58 PM	E96080
2451	Dichloroacetic Acid	[N/A]	ug/L	**54**		EPA 552.1	0.66	1/02/06	6:58 PM	E96080
2452	Trichloroacetic acid	[N/A]	ug/L	**43**		EPA 552.1	0.98	1/03/06	10:31 AM	E96080
2453	Monobromoacetic Acid	[N/A]	ug/L	**0.30**		EPA 552.1	0.28	1/02/06	6:58 PM	E96080
2454	Dibromoacetic Acid	[N/A]	ug/L	**1.2**		EPA 552.1	0.18	1/02/06	6:58 PM	E96080
2456	Total Haloacetic Acids (HAA5)	[60]	ug/L							
2941	Chloroform	[N/A]	ug/L	**140**		EPA 524.2	2.5	12/28/05	9:33 AM	E96080
2942	Bromoform	[N/A]	ug/L	**0.41 U**		EPA 524.2	0.41	12/28/05	3:28 AM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	**23**		EPA 524.2	0.25	12/28/05	3:28 AM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	**2.5**		EPA 524.2	0.30	12/28/05	3:28 AM	E96080
2950	Total Trihalomethanes	[80]	ug/L							

NOTE: Do not round values. Report results to the accuracy, precision, and sensitivity of the analytical method used. Totals for haloacetic acids and total trihalomethanes will be calculated by DEP or DOH.

Reporting Format 62-550.730
Effective January 1995, Revised January 2004

* Results must be reported with appropriate qualifiers in accordance with Florida Administrative Code Rule 62-160, Table 1. Results Qualified with A, F, H, N, O, T, Z, ?, *, are unacceptable for compliance with 62-550. Results qualified with a J, Q, R, or Y must be accompanied by written justification and will be evaluated on a case by case basis. To avoid a monitoring violation, unacceptable results must be replaced with acceptable results from samples collected during the same monitoring peri

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

PUBLIC WATER SYSTEM INFORMATION (to be completed by sampler - Please type or print legibly)

stem Name: FPL MARTIN PLANT PWS I.D. #: 4 4 3 1 7 4 8

System Type (check one) ☐ Community ☒ Nontransient Noncommunity ☐ Transient Noncommunity

Address: 21900 SW WARFIELD BLVD.

City: INDIANTOWN State: FL. ZIP Code: 34956

Phone #: 772-597-7211 Fax #: 772-597-7416

E-Mail Address:

SAMPLE INFORMATION (to be completed by sampler)

Sample Number: PMR-091405 Location Code (if known):

Sample Date: 09/14/05 Sample Time: 7:00 AM

Sample Location (be specific): 3/4 Lab - MRT Grab

Disinfectant Residual (Required when reporting results for trihalomethanes and haloacetic acids): .4 mg/L Field pH:

Sample Type (Check Only One)

- ☐ Distribution
- ☐ Entry Point (to Distribution)
- ☐ Plant Tap not for compliance with 62-550)
- ☐ Raw (at well or intake)
- ☒ Max Residence Time
- ☐ Ave Residence Time
- ☐ Near First Customer

Reason(s) for Sample (Check all that apply)

- ☐ Routine Compliance (with 62-550)
- ☐ Confirmation of MCL Exceedence*
- ☐ Composite of Multiple Sites**
- ☐ Clearance (permitting)
- ☐ Other:

- ☒ Quarterly (Which Qtr? 3 RD)
- ☐ Special (not for compliance with 62-550)
- ☐ Violation Resolution
- ☐ Replacement (of Invalidated Sample)

Sampling Procedure Used or Other Comments:

*See 62-550.500(6) for requirements and restrictions.
Note: See 62-550.512(3) for additional requirements for Nitrate or Nitrite MCL exceedences.

** See 62-550.550(4) for requirements and attach a results page for each site.

Sampler's Name: STAN MCELROY

Sampler's Phone #: 772-597-7640 Sampler's Fax #: 772-597-7416

Sampler's E-Mail Address: STAN_J_MCELROY@FPL.COM

CERTIFICATION (to be completed by sampler)

I, STAN MCELROY (Print Name), LEAD OP. (Print Title)

do HEREBY CERTIFY that the above public water system and sample collection information is completed and correct.

Signature: S. J. McElroy Date: 10/10/05

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

LABORATORY CERTIFICATION INFORMATION (to be completed by lab - Please type or print legibly)

ATTACH A CURRENT DOH ANALYTE SHEET

b Name: Harbor Branch Environmental Laboratories, Inc. Florida Certification #: E96080

Address: 5600 US 1 North Certification Expiration Date: 06/30/2006

Fort Pierce, FL 34946 Phone #: (772) 465-2400 Ext. 285

ANALYSIS INFORMATION (to be completed by lab) Date Sample(s) Received:: 9/14/05

PWS ID (From Page 1): _____ Sample Number (From Page 1): _____

Lab Assigned Report Number or Job ID: 2022517001

Group(s) Analyzed and Results attached for compliance with Chapter 62-550, F.A.C. (Check all that apply):

Inorganics	Synthetic Organics	Volatile Organics	Disinfection Byproducts
☐ All 17	☐ All 30	☐ All 21	☒ Trihalomethanes
☐ Partial	☐ All Except Dioxin	☐ Partial	☒ Haloacetic Acids
☐ Nitrate	☐ Partial		☐ Bromate
☐ Nitrite	☐ Dioxin Only	Radionuclides	☐ Chlorite
☐ Asbestos Only		☐ Single Sample	
		☐ Qtrly Composite**	Secondaries
			☐ All 14
			☐ Partial

Were any analyses subcontracted? ___ Yes X No

If yes, please provide DOH certification numbers: _____

ATTACH DOH ANALYTE SHEET FOR EACH SUBCONTRACTED LAB

CERTIFICATION

I, Cindy Cromer (Print Name) Laboratory Director (Print Title)

do HEREBY CERTIFY that all attached analytical data are correct and unless noted meet all requirements of the National Environmental Laboratory Accreditation Conference (NELAC).

Signature Cindy Cromer Date: 28-Sep-05

* Failure to provide a valid and current Florida DOH lab certification number and a current Analyte Sheet for the attached analysis results will result in rejection of the report, possible enforcement against the public water system for failure to sample, and may result in notification of the DOH Bureau of Laboratory Services.

** Please provide radiological sample dates locations for each quarter.

COMPLIANCE DETERMINATION (to be completed by DEP or DOH)

Sample Collection Info Satisfactory: ☐ Yes ☐ No Sample Analysis Info Satisfactory: ☐ Yes ☐ No

☐ Replacement Sample(s) Requested (circle or highlight group(s) above) ☐ Revised Report Requested (circle or highlight group(s) above)

☐ Additional Monitoring Required (circle or highlight group(s) above)

Reason(s): ☐ MCL(s) Exceeded ☐ Detection(s) ☐ Incomplete Report
☐ Missing Analyte Sheet(s) ☐ Location Unsatisfactory ☐ Analysis Unsatisfactory
☐ Other: _____

Person Notified: _____ Date Notified: _____

Comments: _____

Date Reviewed: _____ DEP/DOH Reviewing Official: _____

ARBOR BRANCH
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600 U.S. 1 North, Fort Pierce FL 34946
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DISINFECTION BYPRODUCTS ANALYSES

62-550.310(3)

Client: Florida Power & Light
Report Number/ Job ID: Martin Plant DW THM/HAA5
Sample Location: 3/4 Lab - MRT Grab
Disinfectant Residual (mg/L: .4
Sample Number: 2022517001
PWS ID: 443-1748
Sampling Date: 9/14/05 7:00
Date Received: 9/14/05 10:50

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2450	Monochloroacetic Acid	[N/A]	ug/L	4.7		EPA 552.1	0.88	9/26/05	8:15 PM	E96080
2451	Dichloroacetic Acid	[N/A]	ug/L	100		EPA 552.1	3.3	9/27/05	5:52 PM	E96080
2452	Trichloroacetic acid	[N/A]	ug/L	99		EPA 552.1	0.98	9/27/05	5:52 PM	E96080
3	Monobromoacetic Acid	[N/A]	ug/L	0.50		EPA 552.1	0.28	9/26/05	8:15 PM	E96080
2454	Dibromoacetic Acid	[N/A]	ug/L	0.52		EPA 552.1	0.18	9/26/05	8:15 PM	E96080
2456	Total Haloacetic Acids (HAA5)	[60]	ug/L							
2941	Chloroform	[N/A]	ug/L	210		EPA 524.2	2.5	9/23/05	10:31 AM	E96080
2942	Bromoform	[N/A]	ug/L	0.41 U		EPA 524.2	0.41	9/22/05	9:39 PM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	32		EPA 524.2	0.25	9/22/05	9:39 PM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	3.3		EPA 524.2	0.30	9/22/05	9:39 PM	E96080
2950	Total Trihalomethanes	[80]	ug/L							

NOTE: Do not round values. Report results to the accuracy, precision, and sensitivity of the analytical method used. Totals for haloacetic acids and total trihalomethanes will be calculated by DEP or DOH.

Reporting Format 62-550.730
Effective January 1995, Revised January 2004

Results must be reported with appropriate qualifiers in accordance with Florida Administrative Code Rule 62-160, Table 1. Results Qualified with A, F, H, N, O, T, Z, ?, *, are unacceptable for compliance with 62-550. Results qualified with a J, Q, R, or Y must be accompanied by written justification and will be evaluated on a case by case basis. To avoid a monitoring violation, unacceptable results must be replaced with acceptable results from samples collected during the same monitoring peri

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DISINFECTION BYPRODUCTS ANALYSES

62-550.310(3)

Client: Florida Power & Light

Sample Location: Trip Blank

Sample Number: 2022517002

Sampling Date: 9/14/05 0:00

Date Received: 9/14/05 10:50

Report Number/ Job ID Martin Plant DW THM/HAA5

Disinfectant Residual (mg/L .4

PWS ID 442-1748

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2941	Chloroform	[N/A]	ug/L	0.25 U		EPA 524.2	0.25	9/22/05	10:12 PM	E96080
2942	Bromoform	[N/A]	ug/L	0.41 U		EPA 524.2	0.41	9/22/05	10:12 PM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	0.25 U		EPA 524.2	0.25	9/22/05	10:12 PM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	0.30 U		EPA 524.2	0.30	9/22/05	10:12 PM	E96080
2950	Total Trihalomethanes	[80]	ug/L							

NOTE: Do not round values. Report results to the accuracy, precision, and sensitivity of the analytical method used. Totals for haloacetic acids and total trihalomethanes will be calculated by DEP or DOH.

Reporting Format 62-550.730
Effective January 1995, Revised January 2004

Results must be reported with appropriate qualifiers in accordance with Florida Administrative Code Rule 62-160, Table 1. Results Qualified with A, F, H, N, O, T, Z, ?, *, are unacceptable for compliance with 62-550. Results qualified with a J, Q, R, or Y must be accompanied by written justification and will be evaluated on a case by case basis. To avoid a monitoring violation, unacceptable results must be replaced with acceptable results from samples collected during the same monitoring peri

HARBOR BRANCH
ENVIRONMENTAL
LABORATORIES, INC.
5600 U.S. 1 North, Fort Pierce FL 34946
Tel: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

CERTIFICATE OF ANALYSIS
[2022517]

Client: Florida Power & Light *Workorder ID:* Martin Plant DW THM/HAA5

Parameter	Qualifier	Result[1]	Units	Reporting Limit	Method	Laboratory Batch	Prep Date/Time	Analyzed Date/Time	Analyst	Lab ID
Laboratory ID: **2022517001** *Sample ID:* **3/4 Lab - MRT Grab**					*Sampled: 09/14/05 7:00* *Matrix: Water*			*Received: 09/14/05 10:50* Results reported on Wet Weight Basis		
Bromodichloromethane		**32**	ug/L	0.25	EPA 524.2	VOC2539		09/22/05 21:39	WR	E96080
Bromoform		**0.41 U**	ug/L	0.41	EPA 524.2	VOC2539		09/22/05 21:39	WR	E96080
Chloroform		**210**	ug/L	2.5	EPA 524.2	VOC2539		09/23/05 10:31	WR	E96080
Dibromochloromethane		**3.3**	ug/L	0.30	EPA 524.2	VOC2539		09/22/05 21:39	WR	E96080
Total THMs		**240**	ug/L	0.50	EPA 524.2	VOC2539		09/22/05 21:39	WR	E96080
Dibromoacetic Acid		**0.52**	ug/L	0.18	EPA 552.1	PEST4569	09/26/05 7:13	09/26/05 20:15	RS	E96080
Dichloroacetic Acid		**100**	ug/L	3.3	EPA 552.1	PEST4569	09/26/05 7:13	09/27/05 17:52	RS	E96080
Monobromoacetic Acid		**0.50**	ug/L	0.28	EPA 552.1	PEST4569	09/26/05 7:13	09/26/05 20:15	RS	E96080
Monochloroacetic Acid		**4.7**	ug/L	0.88	EPA 552.1	PEST4569	09/26/05 7:13	09/26/05 20:15	RS	E96080
Total HAAs		**210**	ug/L	0.18	EPA 552.1	PEST4569	09/26/05 7:13	09/26/05 20:15	RS	E96080
Trichloroacetic acid		**99**	ug/L	0.98	EPA 552.1	PEST4569	09/26/05 7:13	09/27/05 17:52	RS	E96080
Laboratory ID: **2022517002** *Sample ID:* **Trip Blank**					*Sampled: 09/14/05 0:00* *Matrix: Water*			*Received: 09/14/05 10:50* Results reported on Wet Weight Basis		
Bromodichloromethane		**0.25 U**	ug/L	0.25	EPA 524.2	VOC2539		09/22/05 22:12	WR	E96080
Bromoform		**0.41 U**	ug/L	0.41	EPA 524.2	VOC2539		09/22/05 22:12	WR	E96080
Chloroform		**0.25 U**	ug/L	0.25	EPA 524.2	VOC2539		09/22/05 22:12	WR	E96080
Dibromochloromethane		**0.30 U**	ug/L	0.30	EPA 524.2	VOC2539		09/22/05 22:12	WR	E96080
Total THMs		**0.50 U**	ug/L	0.50	EPA 524.2	VOC2539		09/22/05 22:12	WR	E96080

[1]Result Qualifiers: U = Not Detected I = Analyte detected between the Laboratory Method Detection Limit and Laboratory Reporting Limit
Applicable Florida Department of Environmental Protection Qualifiers defined below. Statement of Estimated Uncertainty available upon request.

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

PUBLIC WATER SYSTEM INFORMATION (to be completed by sampler - Please type or print legibly)

System Name: FPL MARTIN PLANT PWS I.D. #: 4 4 3 1 7 4 8

System Type (check one) ☐ Community ☒ Nontransient Noncommunity ☐ Transient Noncommunity

Address: 21900 SW WARFIELD BLVD.

City: INDIANTOWN State: FL. ZIP Code: 34956

Phone #: 772-597-7211 Fax #: 772-597-7416

E-Mail Address:

SAMPLE INFORMATION (to be completed by sampler)

Sample Number: PMR-041205 Location Code (if known):

Sample Date: 04/12/05 Sample Time: 1:00 PM

Sample Location (be specific): 3/4 Lab - MRT Grab

Disinfectant Residual (Required when reporting results for trihalomethanes and haloacetic acids): .4 mg/L Field pH:

Sample Type (Check Only One)

- ☐ Distribution
- ☐ Entry Point (to Distribution)
- ☐ Plant Tap not for compliance with 62-550)
- ☐ Raw (at well or intake)
- ☒ Max Residence Time
- ☐ Ave Residence Time
- ☐ Near First Customer

Reason(s) for Sample (Check all that apply)

- ☐ Routine Compliance (with 62-550)
- ☐ Confirmation of MCL Exceedence*
- ☐ Composite of Multiple Sites**
- ☐ Clearance (permitting)
- ☐ Other:
- ☒ Quarterly (Which Qtr? 2 ND)
- ☐ Special (not for compliance with 62-550)
- ☐ Violation Resolution
- ☐ Replacement (of Invalidated Sample)

Sampling Procedure Used or Other Comments:

*See 62-550.500(6) for requirements and restrictions.
Note: See 62-550.512(3) for additional requirements for Nitrate or Nitrite MCL exceedences.

** See 62-550.550(4) for requirements and attach a results page for each site.

Sampler's Name: STAN MCELROY

Sampler's Phone #: 772-597-7640 Sampler's Fax #: 772-597-7416

Sampler's E-Mail Address: STAN_J_MCELROY@FPL.COM

CERTIFICATION (to be completed by sampler)

I, STAN MCELROY (Print Name), LEAD OPERATOR (Print Title)

do HEREBY CERTIFY that the above public water system and sample collection information is completed and correct.

Signature: S. J. McElroy Date: 7-6-05

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

LABORATORY CERTIFICATION INFORMATION (to be completed by lab - Please type or print legibly)

ATTACH A CURRENT DOH ANALYTE SHEET

Lab Name: Harbor Branch Environmental Laboratories, Inc. Florida Certification #: E96080

Address: 5600 US 1 North Certification Expiration Date: 06/30/2005

Fort Pierce, FL 34946 Phone #: (772) 465-2400 Ext. 285

ANALYSIS INFORMATION (to be completed by lab) Date Sample(s) Received:: 4/13/05

PWS ID (From Page 1): _____ Sample Number (From Page 1): _____

Lab Assigned Report Number or Job ID: 2021241001

Group(s) Analyzed and Results attached for compliance with Chapter 62-550, F.A.C. (Check all that apply):

Inorganics	Synthetic Organics	Volatile Organics	Disinfection Byproducts
☐ All 17	☐ All 30	☐ All 21	☒ Trihalomethanes
☐ Partial	☐ All Except Dioxin	☐ Partial	☒ Haloacetic Acids
☐ Nitrate	☐ Partial		☐ Bromate
☐ Nitrite	☐ Dioxin Only	Radionuclides	☐ Chlorite
☐ Asbestos Only		☐ Single Sample	
		☐ Qtrly Composite**	Secondaries
			☐ All 14
			☐ Partial

Were any analyses subcontracted? ___ Yes X No

If yes, please provide DOH certification numbers: _____

ATTACH DOH ANALYTE SHEET FOR EACH SUBCONTRACTED LAB

CERTIFICATION

I, Cindy Cromer (Print Name), Laboratory Director (Print Title)

do HEREBY CERTIFY that all attached analytical data are correct and unless noted meet all requirements of the National Environmental Laboratory Accreditation Conference (NELAC).

Signature _____ Date: 26-Apr-05

* Failure to provide a valid and current Florida DOH lab certification number and a current Analyte Sheet for the attached analysis results will result in rejection of the report, possible enforcement against the public water system for failure to sample, and may result in notification of the DOH Bureau of Laboratory Services.

** Please provide radiological sample dates /locations for each quarter.

COMPLIANCE DETERMINATION (to be completed by DEP or DOH)

Sample Collection Info Satisfactory: ☐ Yes ☐ No Sample Analysis Info Satisfactory: ☐ Yes ☐ No

☐ Replacement Sample(s) Requested (circle or highlight group(s) above) ☐ Revised Report Requested (circle or highlight group(s) above)

☐ Additional Monitoring Required (circle or highlight group(s) above)

Reason(s): ☐ MCL(s) Exceeded ☐ Detection(s) ☐ Incomplete Report
☐ Missing Analyte Sheet(s) ☐ Location Unsatisfactory ☐ Analysis Unsatisfactory
☐ Other: _____

Person Notified: _____ Date Notified: _____

Comments: _____

Date Reviewed: _____ DEP/DOH Reviewing Official: _____

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Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

DISINFECTION BYPRODUCTS ANALYSES
62-550.310(3)

Client:	Florida Power & Light	Report Number/ Job ID	Martin Plant DW THM/HAA5
Sample Location:	3/4 Lab - MRT Grab	Disinfectant Residual (mg/L	
Sample Number:	2021241001	PWS ID	
Sampling Date:	4/12/05 13:00		
Date Received:	4/13/05 11:25		

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2450	Monochloroacetic Acid	[N/A]	ug/L	4.9		EPA 552.1	0.88	4/22/05	4:22 PM	E96080
2451	Dichloroacetic Acid	[N/A]	ug/L	87		EPA 552.1	3.3	4/22/05	6:30 PM	E96080
452	Trichloroacetic acid	[N/A]	ug/L	64		EPA 552.1	0.98	4/22/05	6:30 PM	E96080
2453	Monobromoacetic Acid	[N/A]	ug/L	0.28 U		EPA 552.1	0.28	4/22/05	4:22 PM	E96080
2454	Dibromoacetic Acid	[N/A]	ug/L	0.80		EPA 552.1	0.18	4/22/05	4:22 PM	E96080
2456	Total Haloacetic Acids (HAA5)	[60]	ug/L							
2941	Chloroform	[N/A]	ug/L	160		EPA 524.2	1.2	4/20/05	4:43 PM	E96080
2942	Bromoform	[N/A]	ug/L	0.41 U		EPA 524.2	0.41	4/19/05	11:44 PM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	32		EPA 524.2	0.25	4/19/05	11:44 PM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	3.7		EPA 524.2	0.30	4/19/05	11:44 PM	E96080
2950	Total Trihalomethanes	[80]	ug/L							

NOTE: Do not round values. Report results to the accuracy, precision, and sensitivity of the analytical method used. Totals for haloacetic acids and total trihalomethanes will be calculated by DEP or DOH.

Reporting Format 62-550.730
Effective January 1995, Revised January 2004

* Results must be reported with appropriate qualifiers in accordance with Florida Administrative Code Rule 62-160, Table 1. Results Qualified with A, F, H, N, O, T, Z, ?, *, are unacceptable for compliance with 62-550. Results qualified with a J, Q, R, or Y must be accompanied by written justification and will be evaluated on a case by case basis. To avoid a monitoring violation, unacceptable results must be replaced with acceptable results from samples collected during the same monitoring peri

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Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

Quality Control Summary

Client: Florida Power & Light
Workorder ID: Martin Plant DW THM/HAA5 **[2021241]**
Received: 4/13/05 11:25

MB=Method Blank LCS=Laboratory Control Sample LCSD=Laboratory Control Sample Duplicate MS=Matrix Spike MSD=Matrix Spike Duplicate DUP=Sample Duplicate

Method Narratives (If Applicable)

HBEL Sample Number	Sample ID	Analytical Method	Description

Quality Control Summary

Method	HBEL Batch	Analyte	Analytical Issue
EPA 552.1			
	PEST4475		
	2021241001	Dichloroacetic Acid	Accuracy - Outside acceptance limits in the MS.
	2021241001	Dichloroacetic Acid	Accuracy - Outside acceptance limits in the MSD.
	2021241001	Dichloroacetic Acid	Precision - Outside acceptance limits between the MS and MSD.

The above due to matrix effects. Accuracy/Precision demonstrated with other QC samples.

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CERTIFICATE OF ANALYSIS

[2021241]

Client: Florida Power & Light *Workorder ID:* Martin Plant DW THM/HAA5

Parameter	Qualifier	Result[1]	Units	Reporting Limit	Method	Laboratory Batch	Prep Date/Time	Analyzed Date/Time	Analyst	Lab ID
Laboratory ID: **2021241001**					*Sampled:* 04/12/05 13:00		*Received:* 04/13/05 11:25			
Sample ID: **3/4 Lab - MRT Grab**					*Matrix:* Water		Results reported on Wet Weight Basis			
Bromodichloromethane		32	ug/L	0.25	EPA 524.2	VOC2471		04/19/05 23:44	WR	E96080
Bromoform		0.41 U	ug/L	0.41	EPA 524.2	VOC2471		04/19/05 23:44	WR	E96080
Chloroform		160	ug/L	1.2	EPA 524.2	VOC2471		04/20/05 16:43	WR	E96080
Dibromochloromethane		3.7	ug/L	0.30	EPA 524.2	VOC2471		04/19/05 23:44	WR	E96080
Total THMs		190	ug/L	0.50	EPA 524.2	VOC2471		04/19/05 23:44	WR	E96080
Dibromoacetic Acid		0.80	ug/L	0.18	EPA 552.1	PEST4475	04/22/05 9:12	04/22/05 16:22	RS	E96080
Dichloroacetic Acid		87	ug/L	3.3	EPA 552.1	PEST4475	04/22/05 9:12	04/22/05 18:30	RS	E96080
Monobromoacetic Acid		0.28 U	ug/L	0.28	EPA 552.1	PEST4475	04/22/05 9:12	04/22/05 16:22	RS	E96080
Monochloroacetic Acid		4.9	ug/L	0.88	EPA 552.1	PEST4475	04/22/05 9:12	04/22/05 16:22	RS	E96080
Total HAAs		160	ug/L	0.18	EPA 552.1	PEST4475	04/22/05 9:12	04/22/05 16:22	RS	E96080
Trichloroacetic acid		64	ug/L	0.98	EPA 552.1	PEST4475	04/22/05 9:12	04/22/05 18:30	RS	E96080

[1]Result Qualifiers: U = Not Detected I = Analyte detected between the Laboratory Method Detection Limit and Laboratory Reporting Limit
Applicable Florida Department of Environmental Protection Qualifiers defined below. Statement of Estimated Uncertainty available upon request.

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Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

March 30, 2005

To: Stan McElroy
Florida Power & Light
Martin Plant PO Box 176
Indiantown, FL 34956

Client: Florida Power & Light
Workorder ID: Drinking WaterTHM/HAA5 **[2021035]**
Received: 3/15/05 11:30

Dear Stan McElroy;

Analytical results presented in this report have been reviewed for compliance with the HARBOR BRANCH Environmental Laboratories Inc.'s (HBEL) Quality Systems Manual and have been determined to meet applicable Method guidelines and Standards referenced in the July 2002 National Environmental Laboratory Accreditation Program (NELAP) Quality Manual unless otherwise noted. The Analytical Results within these report pages reflect the values obtained from tests performed on Samples As Received by the laboratory unless indicated differently.

FDOH Safe Drinking Water Act, Clean Water Act and RCRA Certification #'s:

E96080, E83509, E85370, E84418

Questions regarding this report should be directed to the Report Signatory at (772) 465-2400 Ext. 285 referencing the HBEL Workorder ID [Number].

Respectfully submitted,

Cindy Cromer
Technical Director or Designee

Note: This report is not to be copied, except in full, without the expressed written consent of the HARBOR BRANCH Environmental Laboratories, Inc.

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Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

Method Narratives/FDEP Data Qualifiers

Client: Florida Power & Light
Workorder ID: Drinking WaterTHM/HAA5 **[2021035]**
Received: 3/15/05 11:30

MB=Method Blank LCS=Laboratory Control Sample LCSD=Laboratory Control Sample Duplicate MS=Matrix Spike MSD=Matrix Spike Duplicate DUP=Sample Duplicate

Method Narratives (If Applicable)

HBEL Sample Number	Sample ID	Analytical Method	Description

Data Qualifiers (If Applicable)

HBEL Sample Number	Sample ID	Parameter	Method	Qualifier Code	Qualifier Definition

Quality Control Summary

Method	HBEL Batch	Analyte	Analytical Issue

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

PUBLIC WATER SYSTEM INFORMATION (to be completed by sampler - Please type or print legibly)

System Name: FAL-MARTIN PLANT PWS I.D. #: 4 4 3 1 7 4 8

System Type (check one) [ ] Community [X] Nontransient Noncommunity [ ] Transient Noncommunity

Address: 21900 SW WARFIELD BLVD.

City: INDIANTOWN State: FL. ZIP Code: 34956

Phone #: 772-597-7211 Fax #: 772-597-7416

E-Mail Address:

SAMPLE INFORMATION (to be completed by sampler)

Sample Number: 001 Location Code (if known): 3/4 LAB MRT

Sample Date: 03/15/05 Sample Time: 7:10 AM

Sample Location (be specific): 3/4 Lab-MRT Grab

Disinfectant Residual (Required when reporting results for trihalomethanes and haloacetic acids 1.1 mg/L Field pH:

Sample Type (Check Only One)

- [ ] Distribution
- [ ] Entry Point (to Distribution)
- [ ] Plant Tap not for compliance with 62-550)
- [ ] Raw (at well or intake)
- [X] Max Residence Time
- [ ] Ave Residence Time
- [ ] Near First Customer

Reason(s) for Sample (Check all that apply)

- [X] Routine Compliance (with 62-550)
- [ ] Confirmation of MCL Exceedence*
- [ ] Composite of Multiple Sites**
- [ ] Clearance (permitting)
- [ ] Other:
- [X] Quarterly (Which Qtr? 1ST.
- [ ] Special (not for compliance with 62-550)
- [ ] Violation Resolution
- [ ] Replacement (of Invalidated Sample)

Sampling Procedure Used or Other Comments:

*See 62-550.500(6) for requirements and restrictions.
Note: See 62-550.512(3) for additional requirements for Nitrate or Nitrite MCL exceedences.

** See 62-550.550(4) for requirements and attach a results page for each site.

Sampler's Name: S. MCELROY

Sampler's Phone #: 772-597-7640 Sampler's Fax #: 772-597-7416

Sampler's E-Mail Address:

CERTIFICATION (to be completed by sampler)

I, STAN MCELROY (Print Name), LEAD OPERATOR (Print Title)

do HEREBY CERTIFY that the above public water system and sample collection information is completed and correct.

Signature: S. J. McElroy Date: 4/5/05

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

LABORATORY CERTIFICATION INFORMATION (to be completed by lab - Please type or print legibly)

ATTACH A CURRENT DOH ANALYTE SHEET

Lab Name: Harbor Branch Environmental Laboratories, Inc. Florida Certification #: E96080

Address: 5600 US 1 North Certification Expiration Date: 06/30/2005

Fort Pierce, FL 34946 Phone #: (772) 465-2400 Ext. 285

ANALYSIS INFORMATION (to be completed by lab) Date Sample(s) Received:: 3/15/05

PWS ID (From Page 1): _____ Sample Number (From Page 1): _____

Lab Assigned Report Number or Job ID: 2021035001

Group(s) Analyzed and Results attached for compliance with Chapter 62-550, F.A.C. (Check all that apply):

Inorganics	Synthetic Organics	Volatile Organics	Disinfection Byproducts
☐ All 17	☐ All 30	☐ All 21	☒ Trihalomethanes
☐ Partial	☐ All Except Dioxin	☐ Partial	☒ Haloacetic Acids
☐ Nitrate	☐ Partial		☐ Bromate
☐ Nitrite	☐ Dioxin Only	Radionuclides	☐ Chlorite
☐ Asbestos Only		☐ Single Sample	
		☐ Qtrly Composite**	Secondaries
			☐ All 14
			☐ Partial

Were any analyses subcontracted? ___ Yes X No

If yes, please provide DOH certification numbers: None

ATTACH DOH ANALYTE SHEET FOR EACH SUBCONTRACTED LA

CERTIFICATION

I, Cindy Cromer (Print Name), Laboratory Director (Print Title)

do HEREBY CERTIFY that all attached analytical data are correct and unless noted meet all requirements of the National Environmental Laboratory Accreditation Conference (NELAC).

Signature Cindy Cromer Date: 30-Mar-05

* Failure to provide a valid and current Florida DOH lab certification number and a current Analyte Sheet for the attached analysis results will result in rejection of the report, possible enforcement against the public water system for failure to sample, and may result in notification of the DOH Bureau of Laboratory Services.

** Please provide radiological sample dates locations for each quarter.

COMPLIANCE DETERMINATION (to be completed by DEP or DOH)

Sample Collection Info Satisfactory: ☐ Yes ☐ No Sample Analysis Info Satisfactory: ☐ Yes ☐ No

☐ Replacement Sample(s) Requested (circle or highlight group(s) above) ☐ Revised Report Requested (circle or highlight group(s) above)

☐ Additional Monitoring Required (circle or highlight group(s) above)

Reason(s): ☐ MCL(s) Exceeded ☐ Detection(s) ☐ Incomplete Report
☐ Missing Analyte Sheet(s) ☐ Location Unsatisfactory ☒ Analysis Unsatisfactory
☐ Other: _____

Person Notified: _____ Date Notified: _____

Comments: _____

Date Reviewed: _____ DEP/DOH Reviewing Official: _____

HARBOR BRANCH
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5600 U.S. 1 North, Fort Pierce FL 34946
Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

DISINFECTION BYPRODUCTS ANALYSES
62-550.310(3)

Client: Florida Power & Light
Report Number/ Job ID Drinking WaterTHM/HAA5
Sample Location: 3/4 Lab-MRT Grab
Disinfectant Residual (mg/L _____
Sample Number: 2021035001
PWS ID _____
Sampling Date: 3/15/05 7:10
Date Received: 3/15/05 11:30

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2450	Monochloroacetic Acid	[N/A]	ug/L	**1.8 U**		EPA 552.1	1.8	3/22/05	4:13 PM	E96080
2451	Dichloroacetic Acid	[N/A]	ug/L	**33**		EPA 552.1	1.3	3/22/05	4:13 PM	E96080
2452	Trichloroacetic acid	[N/A]	ug/L	**29**		EPA 552.1	0.39	3/22/05	4:13 PM	E96080
2450	Monobromoacetic Acid	[N/A]	ug/L	**0.56 U**		EPA 552.1	0.56	3/22/05	4:13 PM	E96080
2454	Dibromoacetic Acid	[N/A]	ug/L	**0.47**		EPA 552.1	0.37	3/22/05	4:13 PM	E96080
2456	Total Haloacetic Acids (HAA5)	[60]	ug/L							
2941	Chloroform	[N/A]	ug/L	**70**		EPA 524.2	0.25	3/28/05	6:41 PM	E96080
2942	Bromoform	[N/A]	ug/L	**0.41 U**		EPA 524.2	0.41	3/28/05	6:41 PM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	**13**		EPA 524.2	0.25	3/28/05	6:41 PM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	**1.4**		EPA 524.2	0.30	3/28/05	6:41 PM	E96080
2950	Total Trihalomethanes	[80]	ug/L							

NOTE: Do not round values. Report results to the accuracy, precision, and sensitivity of the analytical method used. Totals for haloacetic acids and total trihalomethanes will be calculated by DEP or DOH.

Reporting Format 62-550.730
Effective January 1995, Revised January 2004

* Results must be reported with appropriate qualifiers in accordance with Florida Administrative Code Rule 62-160, Table 1. Results Qualified with A, F, H, N, O, T, Z, ?, *, unacceptable for compliance with 62-550. Results qualified with a J, Q, R, or Y must be accompanied by written justification and will be evaluated on a case by case basis. avoid a monitoring violation, unacceptable results must be replaced with acceptable results from samples collected during the same monitoring peri

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Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

Chain-of-Custody
and
Agreement to Perform Services

USE BALL POINT PEN
PRESS HARD
COMPLETELY FILL OUT
ALL NON GREYED AREAS
PRINT LEGIBLY

Laboratory not responsible for omitted information

✓ FDOH # E96080 — 5600 U.S. 1 North, Fort Pierce, FL 34946
___ FDOH # E85370 — 307 Coolidge Avenue, Lehigh Acres, FL 33936
___ FDOH # E83509 — 255 Enterprise Rd., Suite 1, Deltona, FL 32725
___ FDOH # E84418 — 2514 Osawaw Blvd., Spring Hill, FL 34607

Company: FRL - MARTIN
Address: 21900 SW WARFIELD BLVD.
INDIANTOWN, FL Zip: 34956
Phone: 772-597-7211 Fax: 772-597-7410
Client Contact: WILLIE WELCH
Project Name: POTABLE THM - HAA5
Sampled By: S. MCELROY

Method(s) of Shipment: HBEL

e-mail:

✓ Standard Laboratory Turn Around Time
Or
Rush in ___ Business Days
Requires Laboratory Approval

For Lab Use Only
Temperature Checked (Y) N
Custody Seals Intact Y N N/a
pH Checked Y N

LAB # 2021035

PRESERVATIVE: Hac, NH4 Cl

ANALYSES REQUESTED: (A) THM, (B) HAA5

Preservation Key
H=Hydrochloric Acid P=Phosphoric Acid
N=Nitric Acid ST=Sodium Thiosulfate
S=Sulfuric Acid
SH=Sodium Hydroxide U=Unpreserved

LAB ID	COLLECTION DATE	COLLECTION TIME	Sample Type*	MATRIX**	# Containers	SAMPLE DESCRIPTION As Will Appear On Report	(A) THM	(B) HAA5	COMMENTS
001	3-15-05	0710	G	DW	3	3/4 LAB - MRT	✓		1.1 ppm Cl2
002	3-15-05	0710	G	DW	1	3/4 LAB - MRT		✓	1.1 ppm Cl2

* Sample Type: G=Grab C=Composite

** Matrix: S=Solid SL=Sludge DW=Drinking Water GW=Ground Water SW=Surface Water WW=Wastewater M=Marine

	RELINQUISHED BY	RELINQUISHED BY	RELINQUISHED BY
Report Results To:	S. McElroy		
	DATE/TIME 3-15-05	DATE/TIME	DATE/TIME
	RECEIVED BY Craig Mueller	RECEIVED BY	RECEIVED FOR HBEL CUSTODY BY Craig Mueller
	DATE/TIME 3/15/05 9:20	DATE/TIME	DATE/TIME 3-15-05 11:30

Distribution: WHITE with REPORT; YELLOW for FILE; PINK to CLIENT; GOLD for SAMPLER

CHAIN PAGE 1 of 1

DOCKET NO. 070007-EI
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HARBOR BRANCH
ENVIRONMENTAL
LABORATORIES, INC.
5600 U.S. 1 North, Fort Pierce FL 34946
Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

Volatile Organic Analysis
62 - 550.310 (2) (b)
(PWS028)

Client: Florida Power & Light Workorder: Potable Tri-Annual Samples

Sample Location: Potable P.O.E. Grab

Sample Number: 2019680001

Sampling Date: 8/25/04 15:00

Preservative: 1:1 Hydrochloric Acid and Sodium Thiosulfate

Date Received: 8/26/04 12:05

ID	Parameter	MCL	Result		Method	MDL	Date	Lab ID
2378	1,2,4-Trichlorobenzene	[70]	**0.41 U**	ug/L	EPA 524.2	0.41	9/01/04	E96080
2380	cis-1,2-Dichloroethene	[70]	**0.21 U**	ug/L	EPA 524.2	0.21	9/01/04	E96080
2955	Total Xylenes	[10000]	**0.46 U**	ug/L	EPA 524.2	0.46	9/01/04	E96080
2964	Methylene chloride	[5]	**0.23 U**	ug/L	EPA 524.2	0.23	9/01/04	E96080
2968	1,2-Dichlorobenzene	[600]	**0.21 U**	ug/L	EPA 524.2	0.21	9/01/04	E96080
2969	1,4-Dichlorobenzene	[75]	**0.23 U**	ug/L	EPA 524.2	0.23	9/01/04	E96080
2976	Vinyl chloride	[1]	**0.32 U**	ug/L	EPA 524.2	0.32	9/01/04	E96080
2977	1,1-Dichloroethene	[7]	**0.23 U**	ug/L	EPA 524.2	0.23	9/01/04	E96080
2979	trans-1,2-Dichloroethene	[100]	**0.35 U**	ug/L	EPA 524.2	0.35	9/01/04	E96080
2980	1,2-Dichloroethane	[3]	**0.29 U**	ug/L	EPA 524.2	0.29	9/01/04	E96080
2981	1,1,1-Trichloroethane	[200]	**0.21 U**	ug/L	EPA 524.2	0.21	9/01/04	E96080
2982	Carbon tetrachloride	[3]	**0.24 U**	ug/L	EPA 524.2	0.24	9/01/04	E96080
2983	1,2-Dichloropropane	[5]	**0.40 U**	ug/L	EPA 524.2	0.40	9/01/04	E96080
2984	Trichloroethene	[3]	**0.36 U**	ug/L	EPA 524.2	0.36	9/01/04	E96080
2985	1,1,2-Trichloroethane	[5]	**0.44 U**	ug/L	EPA 524.2	0.44	9/01/04	E96080
2987	Tetrachloroethene	[3]	**0.24 U**	ug/L	EPA 524.2	0.24	9/01/04	E96080
2989	Chlorobenzene	[100]	**0.30 U**	ug/L	EPA 524.2	0.30	9/01/04	E96080
2990	Benzene	[1]	**0.20 U**	ug/L	EPA 524.2	0.20	9/01/04	E96080
2991	Toluene	[1000]	**0.22 U**	ug/L	EPA 524.2	0.22	9/01/04	E96080
2992	Ethylbenzene	[700]	**0.21 U**	ug/L	EPA 524.2	0.21	9/01/04	E96080
2996	Styrene	[70]	**0.21 U**	ug/L	EPA 524.2	0.21	9/01/04	E96080

HARBOR BRANCH ENVIRONMENTAL LABORATORY
5600 U.S. 1 North, Fort Pierce, FL 34946
(561) 465-2400, Ext. 285

Volatile Organic Analysis
62 - 550.310 (2) (b)
(PWS028)

Client: Florida Power & Light Workorder: Martin Plant DW Scan

Sample Location: Potable POE Grab

Sample Number: 2008810001

Sampling Date: 10/31/01 15:30

Preservative: 1:1 Hydrochloric Acid and Sodium Thiosulfate

Date Received: 11/01/01 9:55

ID	Parameter	MCL	Result		Method	MDL	Date	Lab ID
2378	1,2,4-Trichlorobenzene	[70]	ND	ug/L	EPA 524.2	0.37	11/08/01	E96080
2380	cis-1,2-Dichloroethene	[70]	ND	ug/L	EPA 524.2	0.23	11/08/01	E96080
2955	Total Xylenes	[10000]	ND	ug/L	EPA 524.2	0.30	11/08/01	E96080
2964	Methylene chloride	[5]	ND	ug/L	EPA 524.2	0.49	11/08/01	E96080
2968	1,2-Dichlorobenzene	[600]	ND	ug/L	EPA 524.2	0.35	11/08/01	E96080
2969	1,4-Dichlorobenzene	[75]	ND	ug/L	EPA 524.2	0.28	11/08/01	E96080
2976	Vinyl chloride	[1]	ND	ug/L	EPA 524.2	0.33	11/08/01	E96080
2977	1,1-Dichloroethene	[7]	ND	ug/L	EPA 524.2	0.21	11/08/01	E96080
2979	trans-1,2-Dichloroethene	[100]	ND	ug/L	EPA 524.2	0.18	11/08/01	E96080
2980	1,2-Dichloroethane	[3]	ND	ug/L	EPA 524.2	0.45	11/08/01	E96080
2980	1,1,1-Trichloroethane	[200]	ND	ug/L	EPA 524.2	0.25	11/08/01	E96080
2982	Carbon tetrachloride	[3]	ND	ug/L	EPA 524.2	0.28	11/08/01	E96080
2983	1,2-Dichloropropane	[5]	ND	ug/L	EPA 524.2	0.23	11/08/01	E96080
2984	Trichloroethene	[3]	ND	ug/L	EPA 524.2	0.21	11/08/01	E96080
2985	1,1,2-Trichloroethane	[5]	ND	ug/L	EPA 524.2	0.23	11/08/01	E96080
2987	Tetrachloroethene	[3]	ND	ug/L	EPA 524.2	0.26	11/08/01	E96080
2989	Chlorobenzene	[100]	ND	ug/L	EPA 524.2	0.23	11/08/01	E96080
2990	Benzene	[1]	ND	ug/L	EPA 524.2	0.090	11/08/01	E96080
2991	Toluene	[1000]	ND	ug/L	EPA 524.2	0.18	11/08/01	E96080
2992	Ethylbenzene	[700]	ND	ug/L	EPA 524.2	0.19	11/08/01	E96080
2996	Styrene	[70]	ND	ug/L	EPA 524.2	0.24	11/08/01	E96080

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DISINFECTION BYPRODUCTS ANALYSES

62-550.310(3)

Client: Florida Power & Light
Report Number/ Job ID: Potable Tri-Annual Samples
Sample Location: Potable P.O.E. Grab
Disinfectant Residual (mg/L): _____
Sample Number: 2019680001
PWS ID: _____
Sampling Date: 8/25/04 15:00
Date Received: 8/26/04 12:05

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2450	Monochloroacetic Acid	[N/A]	ug/L	**5.3**		EPA 552.1	0.88	9/01/04	7:26 PM	E96080
2451	Dichloroacetic Acid	[N/A]	ug/L	**120**	L	EPA 552.1	0.66	9/01/04	7:26 PM	E96080
2452	Trichloroacetic acid	[N/A]	ug/L	**100**	L	EPA 552.1	0.20	9/01/04	7:26 PM	E96080
2453	Monobromoacetic Acid	[N/A]	ug/L	**0.28 U**		EPA 552.1	0.28	9/01/04	7:26 PM	E96080
2454	Dibromoacetic Acid	[N/A]	ug/L	**1.3**		EPA 552.1	0.18	9/01/04	7:26 PM	E96080
2456	Total Haloacetic Acids (HAA5)	[60]	ug/L	**230**		EPA 552.1	0.18	9/01/04	7:26 PM	E96080
2941	Chloroform	[N/A]	ug/L	**250**	L	EPA 524.2	0.25	9/01/04	2:00 AM	E96080
2942	Bromoform	[N/A]	ug/L	**0.41 U**		EPA 524.2	0.41	9/01/04	2:00 AM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	**37**		EPA 524.2	0.25	9/01/04	2:00 AM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	**3.9**		EPA 524.2	0.30	9/01/04	2:00 AM	E96080
2950	Total Trihalomethanes	[80]	ug/L	**290**		EPA 524.2	0.50	9/01/04	2:00 AM	E96080

Golder Associates

SUBJECT	Aerator Required Size		
Job No. 063-3495	Made by		Date 9/16/06
Ref. Calc. 002	Checked	SUM	Sheet 1 of 1
	Reviewed		

Martin plant Operator (Stan McElroy) suggested the plant potable water aerator may not be adequate for the required duty. See DN-402 (attached) for Plant Potable Water System Manual

We have a multiple tray aerator manufactured by DeLoach Industries

1) Look at chloroform, based on Calc 1, assume 250 µg/L, flow = 50 gpm per Stan McElroy

Based on sample problem page 245 of AWWA's "Water Quality and Treatment":

convert 50 gpm to air volume, assuming 30:1 ratio as in sample problem

1 gal = 231 cu in = $\frac{231}{1728}$ cu ft = 0.1336 ft³/gal

50 * .1336 = 6.7 ft³/minute

6.7 ft³/min x 30 = 201 $\frac{\text{cu ft}}{\text{min}}$

AMERICAN WATER WORKS ASSOCIATION

Water Quality and Treatment

A Handbook of Community Water Supplies

FOURTH EDITION

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where c_i is the concentration of gas in the water at the influent to the tower, and c_e is the concentration of gas in the water at the exit to the tower.

Again care must be exercised so that the units are consistent. The log mean of the driving force is given by

$$DF_{lm} = \frac{DF_e - DF_i}{\ln (DF_e/DF_i)} \tag{5.30}$$

Example Problem 1 Chloroform at a concentration of 119 μg/L is to be reduced to 11.9 μg/L by an air stripping tower. What is the required height for the following conditions?

L 73 m³ water/(m² tower cross section)(hour (h))
G 2200 m³ air/m² tower cross section)(h); (30:1 air-to-water volume ratio)
T 20°C = 293 K
H_D 2.55×10^{-4} atm L/mg (Table 5.1)
$K_L a$ 30 h^{-1} (given value)

Solution Assume $p_i = 0$ (that is, no chloroform exists in the air entering the tower) and calculate p_e by the material balance equation, Eq. (5.24).

Because the molecular weight of chloroform is 119, $C_i = 1 \times 10^{-3}$ mol/m³. Therefore,

$$L\,dc = G\,dp \qquad \text{[Eq. (5.24)]}$$

$$73(1 \times 10^{-3} - 1 \times 10^{-4}) = 2200(p_e - 0)$$

$$p_e = 2.99 \times 10^{-5} \frac{\text{mol gas}}{\text{m}^3 \text{ air}}$$

Because $0.082T$ L of air are in each mole of air,

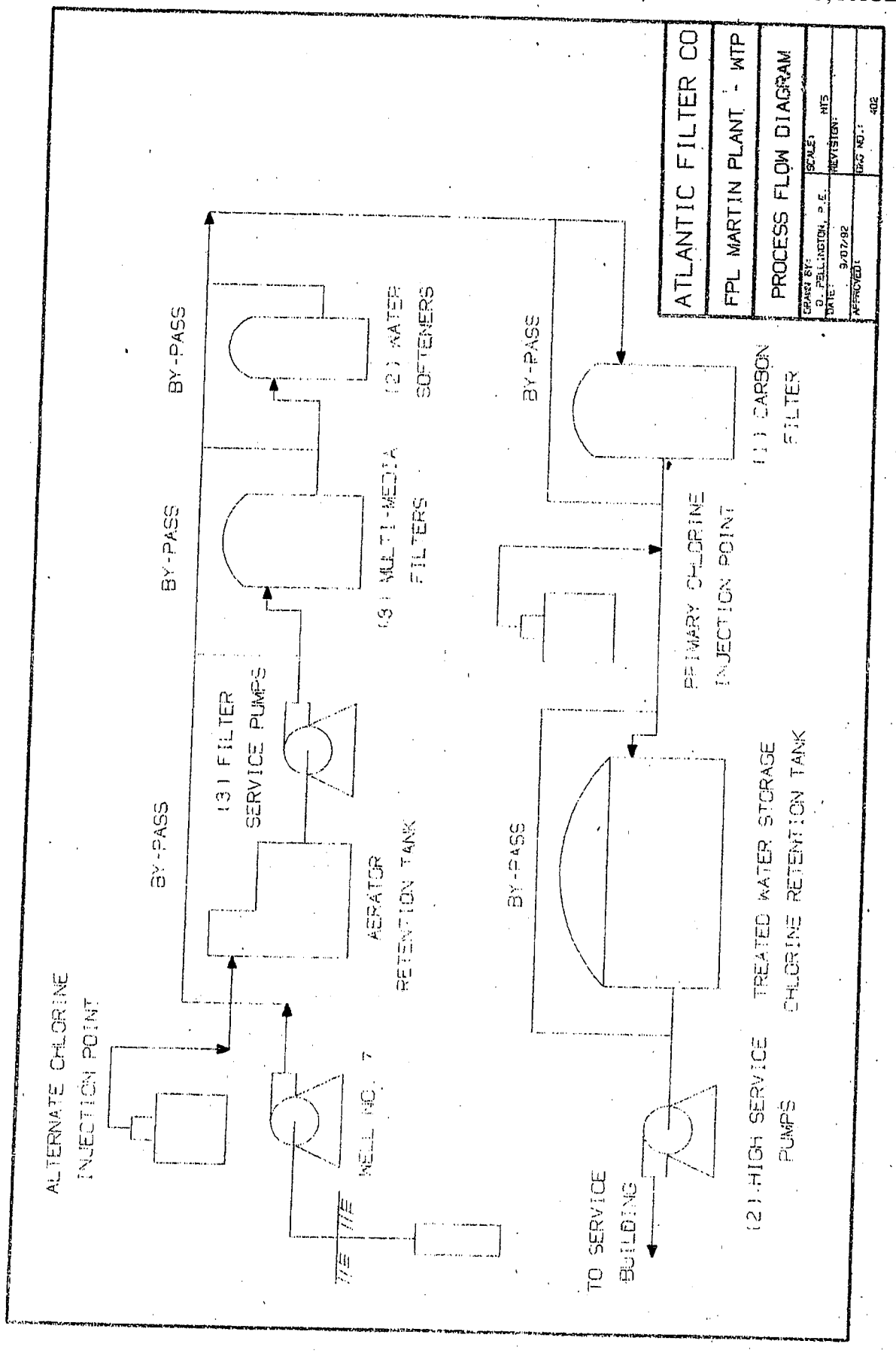
$$p_e = 2.99 \times 10^{-5} \frac{\text{mol gas}}{\text{m}^3 \text{ air}} \frac{0.082(293) \times 10^{-3} \text{ m}^3 \text{ air}}{\text{mol air}}$$

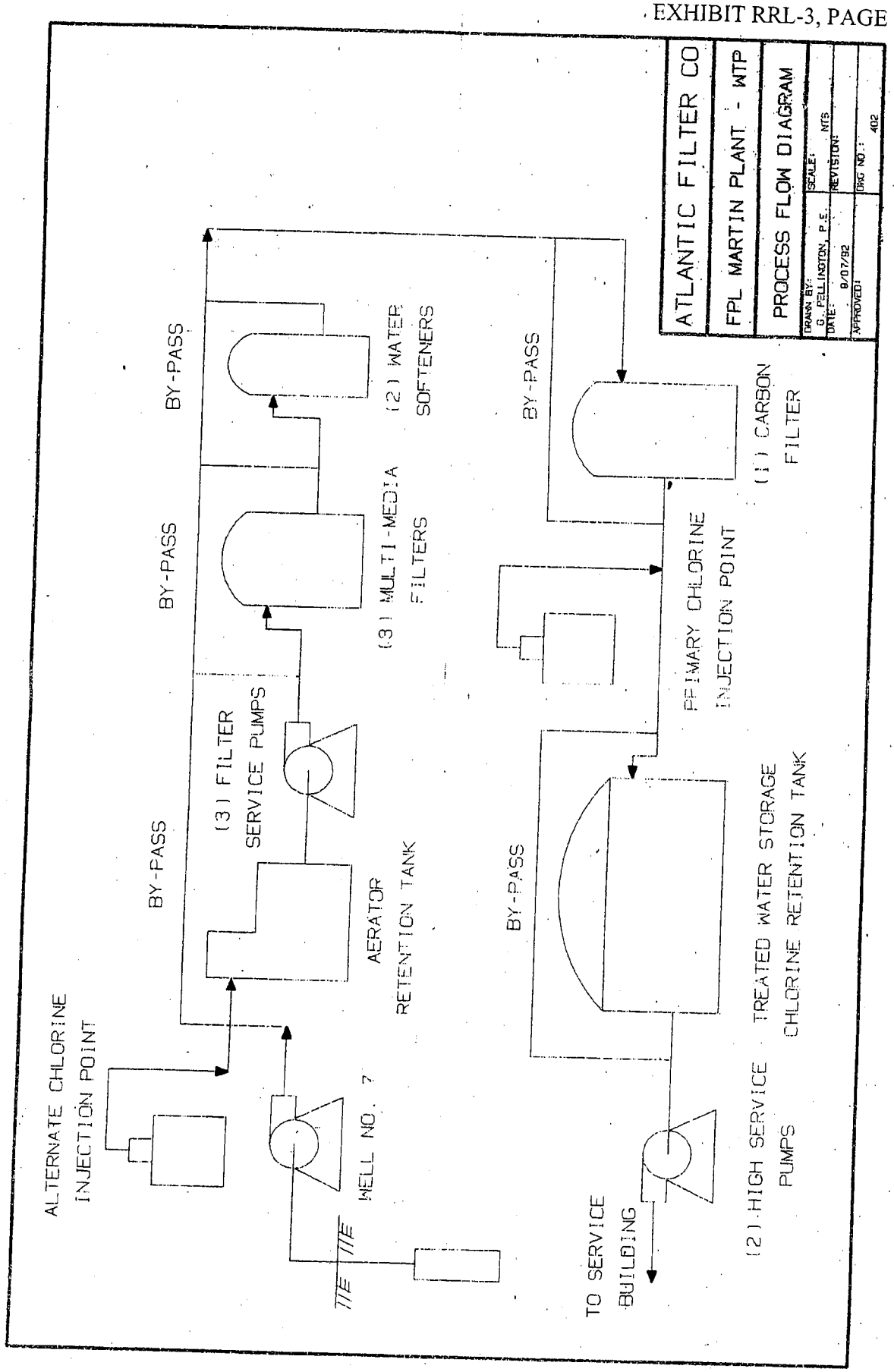
$$= 7.2 \times 10^{-7} \frac{\text{mol gas}}{\text{mol air}}$$

The driving forces are then calculated.

	Concentration in air p, mol gas/mol air	Concentration in water c, mg/L	$c_s = pH_D$, mg/L	$DF = c - c_s$
Exit (top)	7.2×10^{-7}	0.119	0.0282	0.0908
Entrance (bottom)	0	0.0119	0	0.0119

The log mean of the driving force is found by Eq. (5.30)


ATLANTIC FILTER CO
FPL MARTIN PLANT - WTP
PROCESS FLOW DIAGRAM
DRAWN BY: D. PELLINGTON, P.E.
DATE: 3/07/92
APPROVED:
SCALE: NTS
REVISION:
DWG NO.: 402
ALTERNATE CHLORINE INJECTION POINT
WELL NO. 7
(3) FILTER SERVICE PUMPS
AERATOR
RETENTION TANK
BY-PASS
BY-PASS
(3) MULTI-MEDIA FILTERS
(2) WATER SOFTENERS
BY-PASS
PRIMARY CHLORINE INJECTION POINT
(1) CARBON FILTER
BY-PASS
TREATED WATER STORAGE
CHLORINE RETENTION TANK
(2) HIGH SERVICE PUMPS
TO SERVICE BUILDING


ATLANTIC FILTER CO
FPL MARTIN PLANT - WTP
PROCESS FLOW DIAGRAM
DRAWN BY: G. PELLINGTON, P.E.
DATE: 8/07/02
APPROVED:
SCALE: NTS
REVISION:
DWG NO.: 402
ALTERNATE CHLORINE INJECTION POINT
BY-PASS
BY-PASS
BY-PASS
BY-PASS
(3) FILTER SERVICE PUMPS
(3) MULTI-MEDIA FILTERS
(2) WATER SOFTENERS
(1) CARBON FILTER
AERATOR RETENTION TANK
PRIMARY CHLORINE INJECTION POINT
WELL NO. 7
TIE
TIE
TREATED WATER STORAGE CHLORINE RETENTION TANK
(2) HIGH SERVICE PUMPS
TO SERVICE BUILDING

Golder Associates

SUBJECT	GAC Unit Size		
Job No. 063-5495 Ref. Calc 003	Made by NAK Checked SVM Reviewed MD	Date 8/16/06 Sheet	of

The granular activated carbon (GAC) unit (See DN-402 attached to Calc 2) contains 40 cu ft of media, as reported by the Martin Plant Operator (Stan McElroy) during the site visit, and system flow rate is 50 gpm when the well pump is on.

Calculate the Empty Bed Contact Time (EBCT) = $\frac{\text{Bed Volume}}{\text{Flow Rate}} = \frac{40\ ft^3 * \frac{1\ gal}{0.1336\ ft^3}}{50\ gal/min}$

= 6 minutes ✓

Per Reference 2 (AWWA Water Treatment Plant Design), EBCT should be between 5 & 25 minutes

From Plant Data Book, Section 10, page 11, it is actually 39 ft³

→ EBCT = 5.8 minutes

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AMERICAN SOCIETY OF CIVIL ENGINEERS

Water Treatment Plant Design

THIRD EDITION

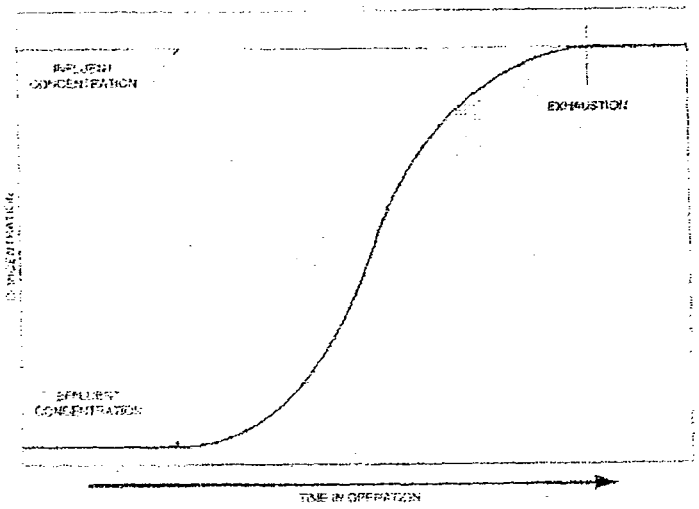


FIGURE 14.3 Breakthrough pattern for GAC filter

the type and depth of carbon and specific solute characteristics. Breakthrough curves are important to the designer because they define the relationship between the physical and chemical parameters of the carbon system (e.g., flow rate, bed size, carbon exhaustion rate), the determination of the number of beds or columns, their arrangement (either series or parallel), and treatment plant effluent requirements.

Empty Bed Contact Time. Empty bed contact time (EBCT) is calculated as the volume of the empty bed occupied by the GAC divided by the volumetric flow rate of water through the carbon. Alternatively, EBCT can be defined as the depth of GAC divided by the linear velocity of water flowing through the carbon bed. It should be noted that EBCT is a false-residence time.

EBCT is used instead of detention time because of the ease of calculation. An actual detention time would have to account for the porosity of the bed, a variable that changes with carbon size and type. EBCT can be varied by changing the bed depth at constant flow or by changing flow with constant bed depth. Together, the design EBCT and the design flow rate define the amount of carbon to be contained in the adsorption units.

Longer EBCTs can delay breakthrough for a point and improve carbon usage rate; shorter EBCTs can expedite breakthrough. Thus the time of GAC operation between replacement or regeneration depends on the EBCT. For most water treatment applications, EBCTs range between 5 and 25 minutes. In addition, a factor having a greater influence on operating costs than EBCT is volume throughput, which is the number of bed volumes of water processed before the breakthrough concentration is reached.

Adsorber Volume and Bed Depth. After the EBCT has been determined, carbon depth can be selected. The adsorber design volume depends on bed volume and the amount of freeboard (space) needed (above and beyond design operating levels). Freeboard can range up

to about 50% for fixed and expanded bed systems. If bed expansion is unnecessary, a freeboard of 20% to 30% may be adequate to allow for proper bed expansion during backwashing.

No freeboard is needed for upflow pulsed beds. An economic evaluation is usually made of capital and operating costs to compare carbon columns of various depths.

Hydraulic Loading Rate. The surface loading rate for GAC filters is related to the design flow of a particular treatment plant. Surface loading rates are defined in the same manner as conventional granular media filters. The surface loading rate is the rate of a volume of water passing through a given area of GAC filter bed, usually expressed as cubic meters per square meter (m^3/m^2) or gallons per minute per square foot (gpm/ft^2). Surface loading rates for GAC filters range from 2 to 10 gpm/ft^2 (5 to 24 m/h), although rates of 2 to 6 gpm/ft^2 (5 to 15 m/h) are more commonly used as design criteria.

Surface loading should be kept large for compounds, where the mass transfer rate is controlled by the rate of transfer of the chemical from the bulk liquid to the interior pores of the GAC. Typically this is the case for highly adsorbable compounds (e.g., many SOCs). When mass transfer is controlled by the rate of adsorption (and transport) within the GAC particle, surface loading is not important. This is the case with most less-adsorbable compounds. Figure 14.4 illustrates the relationship between hydraulic loading and pressure drop for several brands of GAC.

Backwashing. A GAC filter bed is backwashed using the same general procedures typically used for backwashing conventional granular gravity filters. If GAC is installed as a sand filter replacement, a redesign of the backwash supply system, including the rate of flow control and washwater troughs height, is often necessary. This redesign is necessary because of the difference in particle density between GAC and sand—about 1.4 g/cm^3 and 2.65 g/cm^3, respectively. If GAC is used as a simple replacement for anthracite coal as a filter medium, the backwash system may be adequate because particle densities are nearly identical.

GAC particle size distribution and wetted density vary among different carbon brands and even among different deliveries of the same carbon. Appropriate backwash rates can be obtained from the manufacturer for each type of carbon (Figure 14.5). Backwash rates must be adjusted to account for specific media characteristics and for changes in backwash water temperature (Figure 14.6). Installing a surface wash or air scour system to assist with filter cleaning may be necessary to control mudball formation.

A good conservative design should allow for 75% to 100% expansion of light GAC media, but 50% is generally considered to be adequate. The design should provide for sufficient freeboard to reduce media losses during the backwashing cycle.

Carbon Usage Rate. The carbon usage rate (CUR) determines the rate at which carbon will be exhausted and how often the carbon must be replaced. The CUR essentially determines the size of the entire regeneration system. The CUR for GAC systems removing organic compounds may be determined using physical models or adsorption isotherm models. A pilot-scale test is often used to evaluate the complexity of multiple chemical interactions. A quicker and more economical method for evaluating GAC column performance is the rapid small-scale column test (RSSCT). Small systems can be designed to best simulate the performance of a full-scale system using dimensional analysis. Dimensionless parameters for the full-scale system and the small system are designed to be equal.

Carbon treatment effectiveness improves as contact time increases. The percentage of total carbon in a bed that is exhausted at breakthrough is greater in a deeper bed than in a shallower bed. At a point beyond the optimum bed depth, the additional adsorber volume provided acts primarily as a storage capacity for spent carbon. The actual selection of bed depth and corresponding adsorber volume also depends on

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CURVE SHEETS

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SECTION 10 - WATER TREATMENT SYSTEM

1. GENERAL SYSTEM DESCRIPTION

Prechlorinated well water from the raw water storage tank is pumped through the pretreatment system where it is lime softened and filtered. The pretreating equipment consists of a coagulator, clearwell, two treated water transfer pumps and four pressure sand filters. The treated water effluent from the sand filters is routed to the 500,000-gallon treated water storage tank which supplies the treated water requirements of the demineralizer units and miscellaneous plant services. Water from an on-site well serves the potable water system, which consists of a carbon filter, chlorinator, storage tank and two service pumps. The demineralizer system is of the two parallel train design with each train consisting of a strong acid cation unit, a weak base anion unit, a strong base anion unit and a polishing mixed bed unit. Most of the controls and instrumentation are mounted in a control panel conveniently located in the water treating area.

2. PRETREATMENT SYSTEM

The 885 gpm capacity pretreatment system includes prechlorination, cold lime softening, coagulation and filtration of raw well water.

Two coagulator feed pumps, taking suction from the raw water storage tank, deliver the prechlorinated well water through a flow metering device, a pneumatically actuated modulating control valve, and to the coagulator.

The coagulator inlet flow control valve is positioned based on system demand from the clearwell. This is accomplished by positioning the inlet control valve so that the inlet flow rate to the coagulator matches system demand which is derived from the clearwell level. The minimum clearwell level is analogous to maximum demand. At this point, the inlet control valve to the coagulator should be wide open.

The system is automatically shut down at maximum clearwell level which corresponds to essentially zero inlet flow rate. At this point, the inlet control valve closes, the coagulator feed pumps are stopped, and the chemical feeder decanting mechanisms are lifted.

As the system demand increases to approximately 25 percent of the design flow rate, with a corresponding drop in the clearwell level, the inlet control valve opens, the coagulator feed pumps start, and the decanting mechanisms in the chemical feed tanks are lowered.

The coagulator is equipped with an automatic type, timer controlled blowdown system to permit effective removal of sludge. pH monitors are provided for the coagulator effluent, before and after acid addition.

Alum and lime are fed to the coagulator for the purpose of softening and coagulating the raw water supply. Both chemicals are gravity fed through a swing drawoff pipe in each tank which is positioned by a decanting drive. The chemical feed rates are proportional to the service flow. The alum and lime tanks are provided with mechanical agitators and are sized to hold a charge of chemical sufficient for 36 hours of operation at design flow. An additional chemical feed line is provided for the coagulator to permit future injection of coagulant aid, if required.

A bulk lime handling system is provided in order to facilitate and automate the storage, slaking, transfer and conversion of quick lime into lime slurry. Quick pebble lime from the delivery truck is pneumatically conveyed to the top of the lime silo for storage and then gravimetrically fed to the slaker through the discharge hopper. The slaked lime, after removal of grit, flows to the slurry suction tank. A transfer pump, equipped with automatic flushing and recirculation, is provided to transport lime slurry from the suction tank to the holding tank. Lime slurry transfer is automatically initiated based on level in the holding tank. A manual outlet valve is provided for the holding tank to allow gravity transfer of lime slurry into the lime feed tank. Treated water is to be used for the slaking and dilution of lime.

Acid solution is fed to the coagulator effluent in order to reduce the pH of the softened water, thereby, minimizing the possibility of scale formation in the filter beds and related equipment. The acid feed pump is of the positive displacement diaphragm type, equipped with pneumatic stroke adjustor. The signal from the pH meter, which monitors the clearwell influent, regulates the acid feed rate. The capacity of the acid solution feed tank is adequate for 36 hours of operation at design flow.

The coagulated, softened and pH adjusted effluent from the coagulator flows by gravity to a 30,000-gallon clearwell. Two, full capacity treated water transfer pumps transport the water from the clearwell, through four parallel sand filters and to the treated water storage tank. The sand filters are designed to operate at a normal rate of 222 gpm and a maximum rate of 295 gpm while one of the filters is being backwashed or rinsed. Each filter unit is provided with a set of manual valves to permit isolation and manual backwashing, rinsing and return to service. The need for filter backwashing is indicated by high pressure drop and reduced flow through any filter units. Water for filter backwashing is taken from the raw water storage tank. The treated water storage tank level is controlled by an inlet flow control valve.

3. POTABLE WATER TREATMENT SYSTEM

Approximately 50 gpm of well water is routed through a carbon filter. Then, the carbon filter effluent is chlorinated prior to storage. The chlorine feed rate is proportional to potable water flow which, in turn, is regulated by the level controller in the potable water storage tank. The carbon filter is also backwashed based on increase in pressure drop and reduction in service flow. Manual valves for isolation, backwash, rinse and return to service are also provided. Potable water is used for backwashing the carbon filter.

4. DEMINERALIZER SYSTEM

Two 700 gpm capacity demineralizer feed pumps provide the treated water requirements of the ion exchangers. The demineralizer system includes two parallel trains of ion exchange units with each train consisting of a strong acid cation, weak base anion, strong base anion and a mixed bed polisher. Each primary train is designed for 350 gpm; whereas, each mixed bed polisher is nominally rated at 700 gpm capacity. The primary cation units have provisions for future addition of ion exchange resins. The net volumetric throughput between regenerations is 378,000 gallons per primary train and 7,700,000 gallons per mixed bed polisher. Acid and caustic regeneration systems are provided in order to restore the ion exchangeability of the demineralizer units upon exhaustion. Sulfite solution is fed into the demineralizer influent line in order to protect the resins from the oxidative effect of residual chlorine. The treated water influent to the demineralizer units is continuously monitored by a chlorine analyzer. The cleaning of organically fouled ion exchangers is accomplished by the use of the brine recirculation system.

Two 100% capacity, vertical pumps mounted on top of the 10,000-gallon acid storage tank, together with strong acid flow controller, teflon lined mixing tee, dilution water flow controllers, conductivity indicators and control valves, are provided to regenerate the primary cation and mixed bed cation resin beds. The acid solution from the dilution station is also intended for filling up the acid feed tank which serves the coagulator effluent.

Two 100% capacity, vertical pumps mounted on top of the 10,000-gallon caustic storage tank, including strong caustic and dilution water flow controllers, saran lined mixing tee, conductivity indicator, dilution water heat exchanger, thermostatic controller, temperature indicator with alarm switch, and control valves, are all provided to serve the primary weak base and strong base anion, and mixed bed anion resin beds. An air blower is also furnished to properly mix the freshly regenerated and stratified resin layers in the mixed bed unit. The temperature of the dilute caustic solution is to be automatically maintained at 120°F by controlling the steam supply to the dilution water heat exchanger. The caustic storage tank is provided with immersion type electrical heaters in order to maintain a minimum caustic temperature of 70°F.

The brine recirculation system is designed for manual operation with the exception of the brine heater. This system consists of rubber lined brine mixing tank and brine measuring tank, brine solution heat exchanger, thermostatic controller, temperature indicator with alarm switch, pressure gauges, valves and a brine recirculation pump. The dilution water source is demineralized water. The brine recirculation system serves all ion exchangers except the primary cation units. Termination of brine recirculation is determined by visual observation of the brine solution. A manual "dump" valve is provided in the brine return line to the measuring tank, and this allows draining of highly contaminated brine solution.

During normal service conditions, only one demineralizer feed pump is expected to be operating. The influent treated water passes through the cation units where ions of calcium, magnesium and sodium are trapped in and hydrogen ion released from the resin media. The acidic effluent then flows through the weak base anion units where sulfates and chlorides are removed and exchanged for hydroxyl ions. The partially demineralized water then flows through the strong base anion units in order to remove carbon dioxide and silica. Cation and anion leakages, consisting primarily of sodium and silica ions, are removed in the polishing mixed bed unit(s).

After a certain service period, depending on the flow rate and quality of treated water supply, the demineralizer units reach their exhausted state. This service period is determined by volumetric end of run (gallons) or by high conductivity (umhos/cm) in the primary anions and mixed bed units. At the operator's option, the exhausted primary train is regenerated by pushbutton initiation; all succeeding steps are fully automatic. The regeneration system controls are designed to allow regeneration of the cation unit prior to both primary anion units. Regeneration of the primary units essentially includes backwashing, settling, chemical regenerant introduction, displacement and rinse. Another step is included in the anion regeneration procedure, i.e. conductivity check. The regeneration of the primary anion units is accomplished by passing fresh caustic solution first through the strong base and then routing the spent caustic to the weak base unit. The primary cation is regenerated using treated water; decationized water is used for primary anion regeneration.

Regeneration of the mixed bed units is performed in a similar manner except that acid regeneration of the lower and relatively heavier cation resin layer is done countercurrently and prior to caustic regeneration of the upper anion layer. A mid-bed collector serves as a drainage for the chemical waste and the rinse waste. The air blower is turned on after chemical regeneration of the mixed bed. The pressurized air uplifts and mixes the freshly regenerated anion and cation resin layers. Fast rinse and conductivity check are the two last steps in the mixed bed regeneration. Backwash and rinse water is taken from the strong base anion effluent.

Return to service of a newly regenerated primary train or mixed bed polisher is also a pushbutton initiated operation.

All recorders, indicators, annunciators, controls and instrumentation are mounted on the totally enclosed NEMA Class 3, walk-in type control panel. The panel is also provided with air conditioning equipment and glass windows. Individual solenoid valve cabinets are also provided for each skid-mounted demineralizer unit.

5. EQUIPMENT DATA

5.1 Raw Water Chlorinator

Manufacturer	Fisher & Porter
Quantity	One

Type	F & P Model 70C3430 gas chlorinator, vacuum type, with automatic proportioning control, using 3-15 psig square root signal from raw water flowmeter.
Capacity	75 lbs. Cl_2/day
Accessories	Internal heater, weighing scale, gas mask, ejector, diffuser, gauges, valves and connectors.
Use	Chlorinate and condition incoming well water to the raw water storage tank.

5.2 Coagulator

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Circular steel shell and bottom with internal coating of vinyl copolymer, sludge recirculating type with full bottom scraper.
Capacity	885 gpm.
Dimension	37' - 0" dia. x 16' - 0" straight shell.
Rinse Rate	1.0 gpm/ft^2.
Retention Time	90 minutes (minimum) at design rate.
Blowdown System	Inlet meter totalizer and automatically initiated time span blowdown, which will be pneumatically operated.
Recirculation Agitator & Drive	Two Proquip Model No. 1ZEX50 top entering, right angle, turbine trip agitators with 1-1/2 hp motor; one Winsmith speed reducer, Model No. 15CVD.
Blowdown Rate & Frequency	150 gpm for 3 minutes every 15-minute cycle.

Bottom Scraper & Drive	1/4 hp, Reeves "Motodrive," rated for 115 V, single phase, 60 Hz.
Accessories	One set of pH measuring equipment for monitoring of effluent pH.
Sample Connections	Sample connections, piping and valves, sink mounted on coagulator shell.
Use	Softening and coagulation of raw well water.

5.3 Lime Feed System

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Vertical, cylindrical steel tank with bottom dished head, top cover and top loading door for gravity feeding into the coagulator.
Capacity	5000 gallons of 10% by weight lime slurry.
Dimension	11' - 0" dia. x 7' - 0" straight side.

Mixer

Type	Lightnin Model 71Q2 with type 316 stainless steel shaft and impellers.
Motor Rating & Enclosure	2 hp, 460 V, 3 phase, 60 Hz, TEFC.
Accessories	1/6 hp, Graham Model N27MW60 gear motor for swing pipe drive, 115 V, single phase, 60 Hz, reversible 0-9 rpm output; dust evacuator.
Use	Softening of raw well water.

5.4 Alum Feed System

Manufacturer	Hungerford & Terry, Inc.
Quantity	One

Type	Vertical, cylindrical, type 316 stainless steel tank with bottom dished head, top cover and top loading door for gravity feeding into the coagulator.
Capacity	500 gallons of 5% by weight alum solution.
Dimension	4' - 6" dia. x 4' - 0" straight side.
Mixer	
Type	Lightnin Model NLDG-33 with type 316 stainless steel shaft and impellers.
Motor Rating & Enclosure	1/3 hp, 115 V, single phase, 60 Hz, TEFC
Accessories	1/6 hp, Graham Model N27MW60 gear motor for swing pipe drive, 115 V, single phase, 60 Hz, reversible 0-9 rpm output; dissolving basket.
Use	Coagulation of raw well water.

5.5 Acid Feed System

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Vertical, cylindrical, rubber lined steel tank with flat bottom and top cover plate.
Capacity	500 gallons of 10% by weight H_2SO_4 solution.
Dimension	4' - 6" dia. x 5' - 0" high
Feed Pump	
Type	Milton Roy Model AFR-125A-117, diaphragm type metering pump with TFE diaphragm and pneumatic stroke adjustor.
Motor Rating & Enclosure	1/4 hp, 115 V, 1 phase, 60 Hz. TESXT.

Feed Rate	5 gal/hr. of 10% acid solution
Accessories	One set of pH measuring equipment for automatic control of acid feed pump, level switch for automatic filling of tank.
Use	Prevention of carbonate post-precipitation in the clearwell, piping and sand filters.

5.6 Clearwell

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Circular, steel shell, top conical roof, flat bottom with internal coating of vinyl copolymer.
Capacity	30,000 gallons
Dimension	18' - 6" dia. x 16' - 0" high
Accessories	Level indicator, horizontal internal baffles.
Use	Surge tank for softened and coagulated water.

5.7 Treated Water Transfer Pumps

Manufacturer	Worthington
Quantity	Two
Type	Horizontal, centrifugal type, Worthington Model D1011 with bronze impeller and cast iron casing.
Capacity and Head	885 gpm at 115 ft. tdh
Speed	1750 rpm
Motor Rating & Enclosure	50 hp, 460 V, 3 phase, 60 Hz, TEFC.

Accessories	Pressure indication, isolation and check valves, recycle valve
Use	Supply coagulated and softened water to the sand filter units.

5.8 Pressure Sand Filters

Manufacturer	Hungerford & Terry, Inc.
Quantity	Four
Type	Skid-mounted, manual pressure filters designed for parallel operation.
Design Pressure	75 psig ASME Code
Design Flow	295 gpm (maximum rating per unit)
Dimension	9' - 0" dia. x 5' - 0" straight shell
Filter Media & Support Bed	189 ft^3 of filter sand and 84 ft^3 of graded gravel
Backwash Rate & Duration	950 gpm per unit for 10 minutes
Rinse Rate & Duration	200 gpm per unit for 5 minutes
Accessories	Individual flow meters and differential pressure gauges.
Use	Removal of suspended solids from coagulated and softened water.

5.9 Carbon Filter

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Skid-mounted, manual pressure filter.
Design Pressure	75 psig ASME Code

Design Flow	50 gpm
Dimension	4' - 6" dia. x 5' - 0" straight shell
Vessel Lining	3/16" thick rubber
Filter Media	39 ft^3 of activated carbon
Backwash Rate & Duration	100 gpm for 10 minutes
Rinse Rate & Duration	50 gpm for 5 minutes
Accessories	Inlet flow meter and differential pressure gauge.
Use	Removal of trace color and odor.

5.10 Potable Water Chlorinator

Manufacturer	Fischer & Porter
Quantity	One
Type	F & P Model 70C3430 gas chlorinator with automatic proportioning control using 3-15 psig square root signal from carbon filter effluent flowmeter.
Capacity	3 lbs. Cl_2/day
Accessories	Internal heater, weighing scale.
Use	Chlorinate carbon filter effluent in order to meet potable water requirements.

5.11 Sulfite Feed System

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Vertical, cylindrical, type 304 stainless steel tank with flat bottom and hinged cover.

Capacity	100 gallons of 5% by weight sodium sulfite solution.
Feed Pump	
Type	Milton Roy Model FR-111A-117, diaphragm type metering pump with manual stroke adjustor.
Motor Rating & Enclosure	1/4 hp, 115 V, 1 phase, 60 Hz, TESXT.
Feed Rate	2.8 gal/hr. of 5% sulfite solution.
Mixer	
Type	Milton Roy, with type 316 stainless steel shaft and impellers.
Motor Rating & Enclosure	1/4 hp, 115 V, 1 phase, 60 Hz, TESXT.
Accessories	Polyethylene floating cover, type 316 stainless steel dissolving basket, low level pump cut-off switch, external relief valve.
Use	React with residual chlorine present in treated water supply.

5.12 Demineralizer Feed Pumps

Manufacturer	Aurora
Quantity	Two
Type	Horizontal, centrifugal type, Aurora Model 411 with bronze impeller and cast iron casing.
Capacity and Head	700 gpm at 290 ft tdh.
Speed	3500 rpm
Motor Rating & Enclosure	75 hp, 460 V, 3 phase, 60 Hz, TEFC.

Accessories	Pressure regulating valves, pressure indication, relief valve, isolation and check valves.
Use	Supply treated water to the demineralizer units for removal of dissolved solids.

5.13 Cation Exchangers

Manufacturer	Hungerford & Terry, Inc.
Quantity	Two
Type	Skid-mounted, automatic strong acid cation units designed for parallel operation.
Design Pressure	150 psig ASME Code
Design Flow	350 gpm per unit
Dimension	7' - 6" dia. x 8' - 8" straight shell
Vessel Lining	3/16" thick rubber
Resin Volume	184 ft^3 of strongly acidic cation resin, Rohm & Haas IR-120
Regeneration Level	5.0 lbs. of 66° Be H_2SO_4/ft^3 resin
Service Run Between Regeneration	418,000 gallons per unit
Accessories	Inlet flow meters, differential conductivity meters, sight windows, resin traps, inlet chlorine analyzer, solenoid valve cabinets.
Use	Removal of cations such as calcium, magnesium and sodium from treated water supply.

5.14 Weak Base Anion Exchangers

Manufacturer	Hungerford & Terry, Inc.
Quantity	Two
Type	Skid-mounted, automatic weak base anion units designed for parallel operation.
Design Pressure	150 psig ASME Code
Design Flow	350 gpm per unit
Dimension	7' - 6" dia. x 6' - 2" straight shell
Vessel Lining	3/16" thick rubber
Resin Volume	132 ft^3 of weakly basic anion resin, Rohm & Haas IRA-93
Regeneration Level	Spent caustic from strong base anion unit
Service Run Between Regeneration	398,000 gallons per unit
Accessories	Conductivity meters, sight windows, solenoid valve cabinets.
Use	Removal of strongly ionized anions such as sulfate and chloride; entrapment of certain organic compounds.

5.15 Strong Base Anion Exchangers

Manufacturer	Hungerford & Terry, Inc.
Quantity	Two
Type	Skid mounted, automatic strong base anion units designed for parallel operation.
Design Pressure	150 psig ASME Code.

Design Flow	350 gpm per unit
Dimension	7'-6" dia. x 6'-2" straight shell
Vessel Lining	3/16" thick rubber
Resin Volume	132 ft^3 of strongly basic anion resin, Rohm & Haas IRA-402
Regeneration Level	5.0 lbs. of 100% NaOH/ft^3 resin
Service Run Between Regeneration	378,000 gallons per unit
Accessories	Effluent and in-bed probe conductivity meters, sight windows, resin traps, solenoid valve cabinets.
Use	Removal of weakly ionized anions such as silica and carbon dioxide.

5.16 Mixed Bed Exchangers

Manufacturer	Hungerford & Terry, Inc.
Quantity	Two
Type	Skid-mounted, automatic mixed bed units with one unit serving as a spare.
Design Pressure	150 psig ASME Code
Design Flow	700 gpm per unit
Dimension	7' - 6" dia. x 6' - 0" straight shell
Vessel Lining	3/16" thick rubber
Resin Volume	83 ft^3 of Dow's HGR and 66 ft^3 of Dow's SBR-P
Regeneration Levels	6 lbs. of 66° Be H_2SO_4/ft^3 of cation resin and 6 lbs. of 100% NaOH/ft^3 of anion resin
Service Run Between Regeneration	7,700,000 gallons per unit

Accessories	Inlet flow meters, effluent and in-bed probe conductivity meters, sight windows, resin traps, solenoid valve cabinets
Use	Removal of cation and anion leakages, primarily sodium and silica, from the primary units effluent.

5.17 Air Blower

Manufacturer	Roots
Quantity	One
Type	Rotary, positive displacement type, Model 76 RAI-V with cast iron impeller, head-plate and case, steel shafts.
Inlet Capacity	400 cfm at 10 psig
Speed	1280 rpm
Motor Rating & Enclosure	25 hp, 460 V, 3 phase, 60 Hz, TEFC
Accessories	Filter-silencer, pressure relief valve, V-belt drive, flowmeter.
Use	Resin mixing in the mixed bed unit.

5.18 Caustic Dilution Water Heat Exchanger

Manufacturer	Bell & Gosset
Quantity	One
Type	Horizontal shell and U-tube heat exchanger, Model SU-66-21 of type 316 stainless steel construction on tube side.
Design Pressure	150 psig ASME Code
Heating Capacity	Heat 35 gpm of water from 55° to 120°F

Steam Requirements	1175 lbs./hr. of 25 psig saturated steam
Heating Surface Area	22.1 ft^2
Accessories	Pressure relief valve, steam control valve, steam traps, strainers.
Use	Preheat caustic dilution water to achieve better silica removal during anion regeneration.

5.19 Acid Regeneration Pumps

Manufacturer	Taber
Quantity	Two
Type	Vertical, submerged centrifugal type, Taber Model 1292 with Alloy 20 impeller and casing.
Capacity and Head	3 gpm at 115 ft. tdh
Speed	1750 rpm
Motor Rating & Enclosure	7-1/2 hp, 460 V, 3 phase, 60 Hz, TEFC.
Accessories	Pressure indication, isolation and check valves, recycle valve, strainer
Use	Supply 66° Be H_2SO_4 to the acid regeneration system and to the acid day tank in the pretreatment system.

5.20 Caustic Regeneration Pumps

Manufacturer	Taber
Quantity	Two
Type	Vertical, submerged centrifugal type, Taber Model 1292 with type 316 stainless steel impeller and casing.

Capacity and Head	2 gpm at 115 ft. tdh
Speed	1750 rpm
Motor Rating & Enclosure	5 hp, 460 V, 3 phase, 60 Hz, TEFC
Accessories	Pressure indication, isolation and check valves, recycle valve, strainer.
Use	Supply 50% NaOH to the caustic regeneration system.

5.21 Acid Storage Tank

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Horizontal, 25 psig design pressure, ASME code steel tank with ASME F & D heads
Coating	Interior coated with 5 to 6 mils of Plasite No. 3066
Dimension	10' - 0" dia. x 16' - 0" straight shell
Capacity	10,000 gallons
Accessories	Saddle supports, ladders and platforms.
Use	Storage for 66° Be H_2SO_4.

5.22 Caustic Storage Tank

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Horizontal, 25 psig design pressure, ASME code steel tank with ASME F & D heads
Coating	Interior coated with 8 to 10 mils of Plasite No. 7133.

Dimension	10' - 0" dia. x 16' - 0" straight shell
Capacity	10,000 gallons
Accessories	Saddle supports, ladders and platforms
Use	Storage for 50% NaOH.

5.23 Brine Mixing Tank

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Vertical, cylindrical steel tank with flat bottom and cover plate.
Lining	3/16" thick rubber for interior and 6 mils epoxy for exterior surfaces.
Dimension	5' - 6" dia. x 4' - 0" high
Accessories	Strainers
Use	Batching and dissolving tank for brine

5.24 Brine Measuring Tank

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Vertical, cylindrical steel tank with bottom dished head and cover plate.
Lining	3/16" thick rubber for interior and 6 mils epoxy for exterior surfaces
Dimension	9' - 0" dia. x 11' - 0" straight side
Accessories	Level gauge, vent
Use	Surge tank during brine recirculation

5.25 Brine Solution Heat Exchanger

Manufacturer	Bell & Gossett
Quantity	One
Type	Horizontal shell and U-tube heat exchanger, Model SU-66, of type 316 stainless steel construction on tube side.
Design Pressure	150 psig ASME Code
Heating Capacity	Heat 35 gpm of 26% saturated brine solution from 55° to 120°F.
Steam Requirements	1175 lbs./hr. of 25 psig saturated steam
Heating Surface Area	22.1 ft^2
Accessories	Pressure relief valve, steam control valve, steam traps, strainers
Use	Preheat and maintain the temperature of recirculating brine solution

5.26 Brine Recirculation Pump

Manufacturer	LaBour
Quantity	One
Type	Horizontal, centrifugal type, LaBour Model LV with Alloy 20 impeller and casing.
Capacity and Head	35 gpm at 115 ft. tdh.
Speed	3500 rpm
Motor Rating & Enclosure	5 hp, 460 V, 3 phase, 60 Hz, TEFC.
Accessories	Pressure and flow indication, isolation and check valves, strainer, recycle valve, flush valve.

Use	Supply brine solution to the anion resin beds.

5.27 Control Panel

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	NEMA 3 construction, double-tunnel walk-through type, with sloping roof and removable sun canopy
Dimension	16' - 0" long x 9' - 0" deep x 8' - 7-1/2" high
Accessories	Air conditioning equipment, recorders, indicators, annunciators and other instrumentation and controls
Use	Serves as a central operating cubicle for monitoring operations and abnormalities in the water treatment system.

5.28 Bulk Lime Handling System

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Bulk lime handling system consisting of a lime storage silo, a feeder and slaker, a slurry transfer pump, a slurry holding tank, and a control panel.

Lime Storage Silo

Type	Bolted steel construction with bake-on epoxy coating, including bin unloader, truck load line assembly, guardrails, access ladder with cage, high and low level indicators, discharge hopper, vacuum pressure valve, bag filter assembly, a 6" rotary valve with 1/2 hp motor and drive, shear protector and manual slide gate, as supplied by Butler Manufacturing Co.

Capacity	40 tons
Dimension	12' - 0" dia. x 32' - 0" high
Accessories	One Wallace & Tiernan Series A-758 lime slaking system complete with gravimetric feeder and stop-start controls; and one Hungerford & Terry control panel with controls and contacts for starting, stopping and controlling the system.

Lime Slurry Transfer Pump

Type	LaBour type DZT, size 14 2" x 1-1/2" horizontal centrifugal pump, with cast iron casing and type 316 stainless steel open impeller.
Capacity	10 gpm at 75 ft. tdh.
Speed	1800 rpm
Motor Rating & Enclosure	3 hp, 460 V, 3 phase, 60 Hz, TEFC
Accessories	Isolation valves for suction and discharge, slurry pump suction tank (36" dia. x 36" high)

Slurry Holding Tank

Type	Vertical, cylindrical tank of carbon steel construction with top cover and access door, round bottom, and structural steel support.
Dimension	11' - 0" dia. x 4' - 0" straight shell
Accessories	Two Lightnin Model NLDG-200 mixers with 2 hp motors; level controller with type 316 stainless steel probes; control and manual valves.
Use	Storage, gravimetric feeding, slaking and transfer of lime slurry into the holding tank.

DESCRIPTION	Manufacturer	Ingersoll-Rand Company	1
	Size and Type	5" x 9" SB	2
	Tag Number(s)	M-107.1.5	3
	Serial Number(s)		4
	RPM/Number of Stages	1750/Single Stage	5
	Design Efficiency- %/BHP/WR2	72/9.9/100	6
	Shut Off Head-FT.	54	7
	Max. BHP Des Imp.	9.9	8
			9
DESIGN CONDITIONS	Liquid Pumped	Raw Water	10
	Pumping Temperature - °F	95°	11
	Specific Gravity @ P.T.	1.0	12
	Vapor Pressure @ P.T. - PSIA		13
	Viscosity @ P.T. - SSU		14
	Capacity - GPM	735	15
	Discharge Pressure - PSIG		16
	Suction Pressure - PSIG		17
	Differential Head - FT.	35	18
	NPSH: Available/Required - FT.	/7	19
	Minimum Flow - GPM	80	20
			21
CONSTRUCTION	Suction Connection: Size/Rating	8" - 125# ANSI	22
	Facing/Position	Flat Face/Side	23
	Discharge Connection: Size/Rating	5" - 125# ANSI	24
	Facing/Position	Flat Face/Side	25
	Impeller Diameter: Design/Maximum		26
	Bearing Type: Thrust/Radial	Ball	27
	Lubrication	Grease	28
	Oil Piping: (Yes) (No) /Type		29
	Seals: Type/Manufacturer	Mechanical/Borg-Warner	30
	Coupling: Type/Manufacturer/Guard	Gear Spacer/Fast "B"/Yes	31
	Water Required: GPM/Pressure		32
	Base Plate: Type/Material	Drip Lip - Fab. Steel	33
			34
MATERIALS	Casing: Inner/Outer	ASTM A-48 Cl.30	35
	Impellers	ASTM B-143	36
	Diffusers		37
	Shaft	AISI - 316 S.S.	38
	Shaft Sleeves	AISI - 316 S.S.	39
	Wear Rings: Case/Impeller	Bronze/None	40
	Packing		41
			42
TESTS	Hydrostatic/Witnessed		43
	NPSH/Witnessed		44
	Performance/Witnessed		45
			46

DRIVER: Type 10HP Motor 1800 RPM 3 Phase 60 Cycle TEFC Frame 215T — 47
Manufacturer/Furnished By Westinghouse — 48
WEIGHTS: Pump/Base/Driver Pump with base 740# Motor 120# — 49
50

SPECIAL FEATURES & ACCESSORIES:

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HORIZONTAL CENTRIFUGAL PUMP DATA SHEET
COAGULATOR FEED PUMP
FLORIDA POWER & LIGHT CO. - MIAMI, FLORIDA
MARTIN PLANT UNITS #1 & #2

CONTRACT NO. CR-0163
SPEC. NO. M-107.1.5
PAGE NO. 22

DESCRIPTION	Manufacturer	Ingersoll-Rand Company
	Size and Type	5" x 4" x 12" HC (Dual)
	Tag Number(s)	M-107.1.9
	Serial Number(s)	
	RPM/Number of Stages	1750/Single Stage
	Design Efficiency - %/BHP/WR2	75/39/
	Shut Off Head-FT.	141
	Max. BHP Des Imp.	39
DESIGN CONDITIONS	Liquid Pumped	Water
	Pumping Temperature - °F	95°
	Specific Gravity @ P.T.	1.0
	Vapor Pressure @ P.T. - PSIA	
	Viscosity @ P.T. - SSU	
	Capacity - GPM	1000
	Discharge Pressure - PSIG	
	Suction Pressure - PSIG	
	Differential Head - FT.	116
	NPSH: Available/Required - FT.	/18
	Minimum Flow - GPM	100
CONSTRUCTION	Suction Connection: Size/Rating	5" - 125# ANSI
	Facing/Position	Flat Face/Front
	Discharge Connection: Size/Rating	4" - 125# ANSI
	Facing/Position	Flat Face/Top
	Impeller Diameter: Design/Maximum	
	Bearing Type: Thrust/Radial	Ball
	Lubrication	Oil
	Oil Piping: (Yes) (No) /Type	
	Seals: Type/Manufacturer	Mechanical/Borg-Warner
	Coupling: Type/Manufacturer/Guard	Gear-Spacer/Fast-"B"/Yes
	Water Required: GPM/Pressure	
	Base Plate: Type/Material	Drip Lip/Fab. Steel
MATERIALS	Casing: Inner/Outer	ASTM - A-48 C.I. 30
	Impellers	ASTM B-143
	Diffusers	
	Shaft	AISI - 1045
	Shaft Sleeves	SAE 660
	Wear Rings: Case/Impeller	SAE 660/None
	Packing	
TESTS	Hydrostatic/Witnessed	
	NPSH/Witnessed	
	Performance/Witnessed	

DRIVER: Type 50 HP Motor 1800 RPM 3 PHASE 60 Cycle EEFC Frame 346TS
Manufacturer/Furnished By Allis Chalmers
WEIGHTS: Pump/Base/Driver Pump with base 512# Motor 835#

SPECIAL FEATURES & ACCESSORIES:

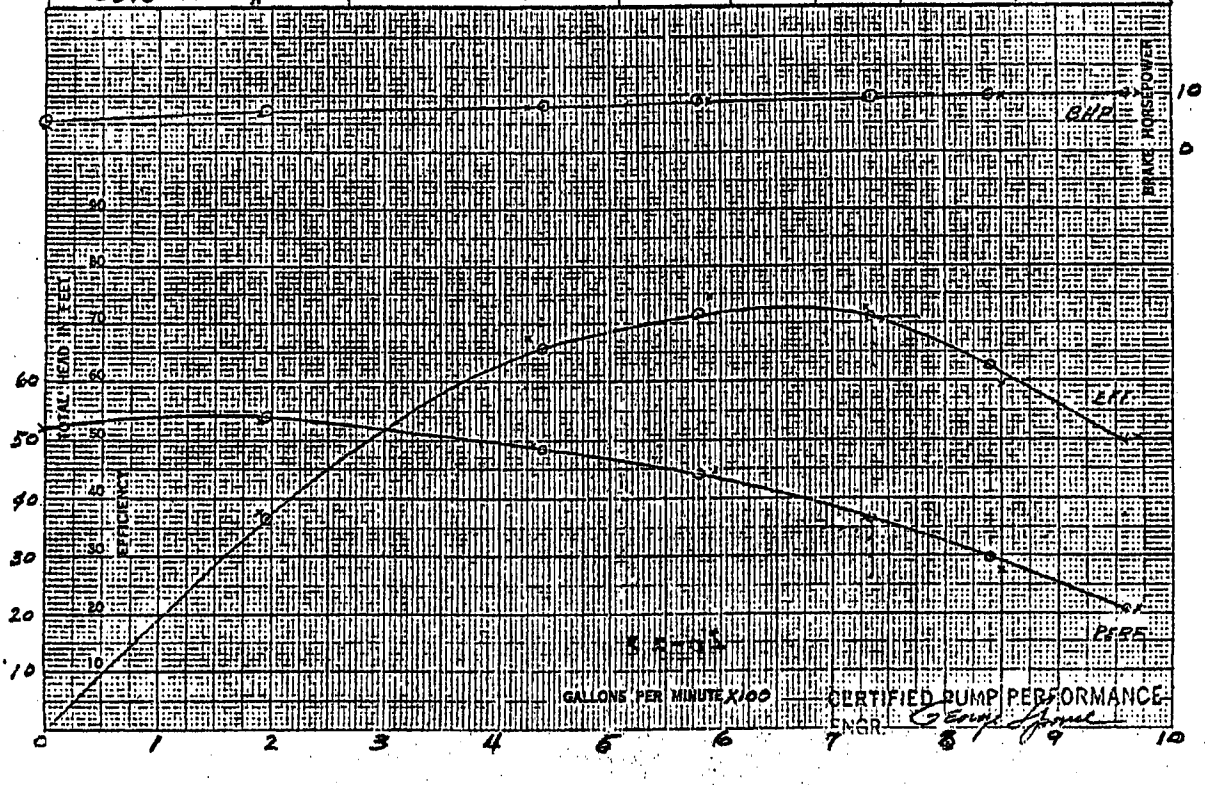
MID-VALLEY, INC.
•ENGINEERS•
•CONSTRUCTORS•
HOUSTON, TEXAS

HORIZONTAL CENTRIFUGAL PUMP DATA SHEET
SAND FILTER BACKWASH PUMP
FLORIDA POWER & LIGHT CO. - MIAMI, FLORIDA
MARTIN PLANT UNITS #1 & #2

CONTRACT NO. CR-0163
SPEC. NO. M-107.1.9
PAGE NO. 23

P.O.# 85-4235-0049 (M-107.1) CUST. ITEM # 4 C# 41502
TAG # 85-4234 (CR-0162) MARTIN UNIT #1
TAG # M-107.1-5A & B COAGULATOR FEED PUMPS 1A & 1B

CUSTOMER: Mid Valley INC.	ORDER CONDITIONS	PUMP 5x9SB				TEST RPM 1750	DATE 8/30/76
ORDER NO. 002-31654 ITEM 2	GPM 735 EFF 71%	IMPELLER	SHROUD DIA.	VANE DIA.	DIFFUSOR		CASING MAT'L.
SERIAL NOS. 0375-651-0	T. H. (FT.) 35' BHP	5583B	7 1/16"				IMP. MAT'L.
0375-652-X	RPM 1750 DRIVER 10 HP MOTOR						DIFF. MAT'L.



MID-VALLEY, INC. *ENGINEERS* *CONSTRUCTORS* HOUSTON, TEXAS	PUMP CURVE SHEET COAGULATOR FEED PUMPS 1A & 1B FLORIDA POWER & LIGHT CO. - MIAMI, FLORIDA MARTIN PLANT - UNITS #1 & #2	CONTRACT NO. CR-0163 SPEC. NO. M-107.1 PAGE NO. 24

FLORIDA POWER & LIGHT COMPANY

Department of Environmental Protection
Letter approving Corrective Action Plan
For FPL Martin Plant PWS #4431748

RRL-4
DOCKET NO. 070007-EI
FPL WITNESS: R.R. LABAUVE
EXHIBIT _____
PAGES 1-3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 10
COMPANY Florida Power + Light
WITNESS R. R. LaBauve (RRL-4)
DATE 11-06-07

Department of Environmental Protection

Jeb Bush
Governor

Southeast District
400 N. Congress Avenue, Suite 200
West Palm Beach, Florida 33401

Colleen M. Castille
Secretary

DEC - 1 2006

Craig W. Arcari, Plant General Manager
Florida Power & Light Company Martin Plant
P.O. Box 176
Indiantown, Florida 34956-0176

Received 12/7/2006
Craig W. Arcari
Craig W. Arcari
General Manager

SUBJECT: Consent Order in OGC File No.: 06-0744
Florida Power & Light Martin Plant PWS #4431748

Dear Mr. Arcari:

The Department would like to thank you for your correspondence of November 17, 2006 regarding the proposed corrective action plan (Plan) required by paragraph 5a of the referenced Consent Order. Based on the additional information provided in your November 17, 2006 letter, the Department hereby approves the Plan and proposed compliance schedule (copy attached). Since the pilot study is proposed to last no more than three months and the water from the pilot plant will not be discharged into the public water system, no Department permit is required for the pilot study.

Please keep the Department apprised as each milestone of the Plan is completed. If you have any questions regarding this matter, please contact Michele Owens of this office at (561) 681-6700 or via email at Michele.Owens@dep.state.fl.us.

Sincerely,

Todd R. Brown, C.P.M.
Environmental Manager
Water Facilities Compliance/Enforcement Program

TRB/mo

Enclosure (all)

cc: Harold A. Frediani, Jr., P.E., P.H., Golder Associates, Inc., 3730 Chamblee Tucker Road, Atlanta, GA 30341
Willie Welch – FPL, P.O. Box 176, Indiantown, FL, 34956 Willie_Welch@FPL.com
Jerry Toney – DEP/PSL Jerry.Toney@dep.state.fl.us
Jose Calas – DEP/WPB Jose.Calas@dep.state.fl.us

Florida Power & Light Company
Martin Plant, P. O. Box 176, Indiantown, FL 34956-0176

DOCKET NO. 070007-EI
DEPT. LETTER APROVING
CORRECTIVE ACTION PLAN
EXHIBIT RRL-4, PAGE 2 OF 3

FPL

November 17, 2006

Mr. Todd Brown, Environmental Manager
Water Facilities Compliance/Enforcement Program
Florida Department of Environmental Protection
Southeast District Office
400 N. Congress Avenue, Suite 200
West Palm Beach, FL 33401

Re: Florida Power & Light Company
Martin Plant
PWS #4431748
OGC File No. 06-0744

Dear Mr. Brown:

FPL is in receipt of the Department's letter dated October 17, 2006, for the FPL Martin Plant nontransient noncommunity public water system, PWS #4431748. In response to the Department's letter, FPL has revised its schedule so that its pilot study will last less than three months. In addition, the water from the pilot study will not be discharged into the public water system. Provided are the revised interim milestone dates for the schedule provided in the Golder Associates submittal dated August 29, 2006. Please note that the remaining dates have not been changed.

- October 17, 2006 – FDEP issues written request for additional information (RFI);
- November 17, 2006 – FPL provides additional information to FDEP;
- December 20, 2006 – FDEP issues written approval of the plan;
- January 12, 2007 – FPL completes measurements of physical characteristics of aeration system, and takes synoptic samples of inlet and outlet water for both the aerator and the carbon filter, and sends those samples to the laboratory;
- January 26, 2007 – FPL receives results/report from laboratory;
- March 23, 2007 – Install pilot equipment for testing; – May 20
- June 20, 2007 – Complete testing of pilot;

In addition, please address any future correspondence to Mr. Craig W. Arcari, FPL Martin Plant General Manager. If you have any questions or need additional information, please contact Willie Welch or Jill Watson at (772) 597-7211 and (561) 694-4304, respectively.

Sincerely,

Craig W. Arcari
Plant General Manager

cc:

Willie Welch	FPL Martin Plant
Jill Watson	Power Generation
Harold Frediani	Golder Associates

Florida Power & Light Company

Clean Air Interstate Rule

800 MW Cycling Project

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI **EXHIBIT** 11
COMPANY Florida Power & Light
WITNESS R. R. LaBauve (RRL-5)
DATE 11-06-07

Project Summary

FPL identified significant potential reductions in annual and ozone season NOx emissions through removal of the "must-run" status from the Martin and Manatee Plant 800 MW units. The "must run" status requires system dispatch to keep the 800 MW units from cycling off line during the May through September period once dispatched for load to avoid premature component failure from unit thermal cycling. FPL identified several strategies which, upon completion, would allow removal of "must run" status without subjecting the 800 MW units to premature failure from cycling off-line in response to reduced system load requirements.

Project Details

The analyses of components and systems which would require specific initiatives to allow for increased unit cycling identified seven (7) changes to component systems: 1)Condenser; 2)Superheater; 3)Economizer; 4)Aux Steam System; 5) Steam Turbine Components; 6)Water Treatment Plant upgrades; & 7)Instrument/Control upgrades. Systems and components were identified based on engineering analysis of impacts to unit reliability resulting from increased unit cycling operation. Figure 1 illustrates the specific project tasks which FPL has identified to allow reliable cycling of the 800 MW units.

Figure 1

ITEM	COUNTEMEASURE	BUDGET TYPE
2	Bullnose Thermocouples	Capital
6	Auxiliary Steam Warming	Capital
8	Steam Line Before Seat Drains	Capital
9	Induced Draft Fan Outlet Isolation Dampers	Capital
10	Nitrogen Blanket	Capital
11	Reheat Dissimilar Welds	Capital
12	Final Super Heater Tube Replace	Capital
13	Reheat Flex Modification	Capital
15	Water Treatment Plant	Capital
17	Condenser Retube	Capital
22	Water Induction Prevention	Capital
24	Rotor Stress Monitor	Capital
30	High Pressure Lower Shell Heating Blankets	Capital
1	Final Super Heater Outlet Header Condition Assessment	O & M
4	Automatic Heat Recovery Area Drains	O & M
5	Boiler Corrosion Fatigue Condition Assessment	O & M

20	Feed Water Recirculation Regulator Inspection	O & M
21	Low Pressure Turbine Inspections	O & M
26	Solid Particle Erosion Coating 2 Stages	O & M
33	Mid-Standard Low Friction Skids	O & M

FPL also identified additional initiatives that would be necessary for implementation of the 800 MW cycling project but were not exclusive to removal of the must run status. FPL intends to perform the additional tasks during planned outages recovering those costs through existing funding sources. Those activities and costs which were identified as specifically required for implementation of the 800 MW cycling project have been included in FPL's request for recovery under the ECRC CAIR docket.

Project Revenue Requirements

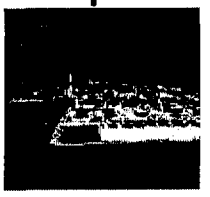
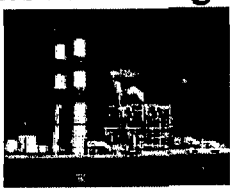
FPL has projected the total cost for implementation of the 800 MW cycling project at $109.3 million for the period of 2007 through project completion in 2010. FPL has identified $101.6 million of project costs which FPL proposes to recover through the ECRC. Figure 2 provides the project funding requirements for implementation of the 800 MW cycling strategy.

Figure 2
800 MW Cycling Project
ECRC Funding Requirement

	2007	2008	2009	2010	Total
Capital	$0	$31,215,000	$47,700,000	$18,150,000	$97,065,000
O&M	$0	$800,000	$2,500,000	$1,248,000	$4,548,000

AES 07016369-2-1
April 2007

Draft Report for Review and Recommendations for Martin and Manatee Power Stations with Future Operation Mode Changes

Phase 1: Analysis of Martin Unit 2 Cycling Impacts on Reliability, Future Costs, and Evaluation of Countermeasures to Reduce Impacts

Prepared By

G. Paul Grimsrud
Steven A. Lefton
James J. Yavelak
Dwight D. Agan
Joseph Lesiuk
Philip M. Besuner

APTECH

Prepared For

Florida Power & Light Company
Power Generation
700 Universe Boulevard
Juno Beach, FL 33408

Section 1
INTRODUCTION

1.1 BACKGROUND AND OBJECTIVES

Florida Power & Light Company (FPL) owns and operates four large gas-fired steam units at the Martin and Manatee power plants. The Martin plant went on-line commercially in 1980. It consists of two conventionally fired oil and gas-fired units. Each unit has a Foster Wheeler boiler, a Westinghouse turbine, and an ABB generator. These units were originally designed to burn oil and were retrofitted in 1985 to also burn natural gas. The Manatee plant first went on-line commercially in 1976. It too consists of two conventionally fired oil and gas-fired units. Each unit has a Foster Wheeler boiler, a Westinghouse turbine, and a Westinghouse generator. Like the Martin plant, the Manatee units were originally designed to burn oil only and were retrofitted in 2002 to also burn natural gas. The Unit 1 boiler at Manatee has been converted to include "re-burn" technology. The Unit 2 boiler is also in the process of installing the "re-burn" technology.

FPL anticipates that the "operating modes" for these units may involve more off-on cycling. FPL is concerned that increased cycling will cause accelerated damage to many unit components, causing increased equipment failures with resulting higher equipment forced outage rates and higher non-routine maintenance and capital replacement costs. The specific operating modes FPL desires to investigate are: (1) cycling off during weekends and (2) cycling off each weeknight (e.g., approximately five startups per week during the seasons of operation).

6.5 RECOMMENDATIONS ON SELECTED COUNTERMEASURES

Based on analyses presented in Table 6-4, we recommend the following cycling countermeasure for detailed design and implementation. These recommendations would apply for both the weekly cycling and daily cycling scenarios.

1. Add auxiliary steam from Unit 8 during periods before startups to lower temperature ramp rates and thermal fatigue in several components, including HP FW heaters; boiler pressure parts; air pre-heater; turbine casing and valves; main steam and hot reheat piping; steam jet air ejector, and the BFP. The economics presented in Table 6-4 do not include the possible benefit to Unit 8 of reducing off-on cycles of a CT. The avoidance of an overnight CT cycle could more than offset the cost of lost MWhs from the Unit 8 steam turbine. In comparing the incremental costs and benefits of including turbine warming from this system to using electric turbine blankets, we think it's more beneficial and less expensive to use the electric turbine blankets.

2. Add Automatic drains in HRA headers with motor-operated valves. This is based on our diagnosis that condensate is present in the lower HRA system left over from the boiler cold or warm condition that causes high thermal shocks to the HRA, division walls, and primary SH. This countermeasure is relatively inexpensive, and will likely significantly decrease problems in the HRA and division walls.

3. Add turbine blankets for keeping warm during shutdowns. We prefer this option compared to using an auxiliary steam source because it is a little cheaper, and much less costly to operate (per hour), meaning it could be used throughout the shutdowns rather than just before startups, thus reducing temperature ranges on warm and cold start cycles.

4. Install a nitrogen blanketing system for the boiler during shutdowns and for continuous use on the condensate storage tank. This system will allow better control of oxygen levels during cycling and help prevent corrosion in the boiler.

The candidate countermeasure that is near the margin in terms of cost-benefit is the condenser re-tube. Part of the reason for this is its high cost, about $7 million per unit. The re-tube option becomes economically viable when one of two adverse effects occur with the current condensers: (1) the condenser tube leaks become frequent and cause significant increases in EFOR and also carryover of bad water to the boiler and turbine and (2) the increasing number of plugged tubes causes condenser backpressure problems that increase heat rates. We think that if the Martin units go to daily cycling that the condensers will degrade very quickly causing and unacceptable level of EFORs. Thus, at least for the daily cycling scenario, we think this countermeasure should be designed and implemented. Since the condenser of Martin Unit 1 appears to be in the worst condition, it should probably be re-tubed first. If the Martin units go to weekly cycling FPL may want to take a wait-and-see approach to re-tubing, thus deferring a large capital cost. However, based on the recent studies on the condensers, they will need to be replaced soon in any case.

The countermeasures that don't appear to be economically viable are the :

1. Bypass system, which is quite expensive and does not offer as much benefit as the auxiliary steam system which is recommended

2. Motor-driven BFP, which appears to be too expensive. We think the auxiliary steam supply could be helpful in reducing BFP problems during initial startup

3. Replacement of selected sections of the SH and RH or replacement of DMWs, which is also too expensive. We think that more information on the damage mechanisms and remaining useful lives of these boiler sections are needed to justify the costs of these options.

Florida Power & Light Company

Clean Air Interstate Rule

Peaking Gas Turbine CEMS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI **EXHIBIT** 12
COMPANY Florida Power & Light
WITNESS R.R. LaBauve
DATE 11-06-07

Project Summary

FPL's Simple Cycle Gas Turbine Peaking Units located at the Port Everglades, Lauderdale and Ft. Myers plants are CAIR affected units which require compliance with the emission monitoring requirements under 40 CFR Part 75. Monitoring requirements under Part 75 provide several compliance options for peaking units. The flexibility for monitoring systems for peaking units allows facilities to implement less data intensive monitoring systems at lower costs exchange for typically higher estimated emissions. The Low Mass Emissions (LME) monitoring option under Part 75.19 is available to units which emit less than 100 NOx tons annually and 50 NOx tons during the May through September Ozone Season.

FPL had initially chosen to comply with the CAIR Part 75 monitoring requirements at the Gas Turbine Peaking Units through fuel flow monitoring methodology of Subpart B – Monitoring Provisions. Compliance utilizing the fuel flow methodology would have required a limited CEMS implementation to capture fuel flow to each unit and calculated the emissions through use of the emission factors provided by EPA for similar LME units.

During a subsequent review of the LME compliance option it was identified that an unacceptable risk to operation of the Gas Turbine Peaking Units could occur under several operating scenarios. The Part 75 rules do not allow for exceptions to compliance requirements and limitations for operating issues including emergency operations resulting from impacts of storms to FPL. FPL identified that exceedance of the LME limits for use of the fuel flow methodology was possible and theat exceedance of the limit would require compliance with full Part 75 CEMS requirements for all units within 12 months of the exceedance. Full Part 75 CEMS compliance would require the installation of stack sampling ports, pollutant analyzers, on data acquisition & reporting systems on each combustion turbine. FPL has estimated compliance with implementation of a full Part 75 CEMS on all of the Peaking Gas Turbine Units at a total cost in excess of $1.5 million for installation.

To reduce the potential exposure to a required implementation of full Part 75 CEMS on all Gas Turbine Peaking Units FPL has identified that compliance with the Similar Units methodology under the LME provisions would be a more cost effective alternative for CEMS compliance. FPL plans to implement the Similar Units provision through establishing emission factors from actual unit emission testing and monitoring of representative units. Emission factors will be developed for one of every four similar Gas Turbine Peaking Units to estimate emissions from the other units in the group.

The CAIR Gas Turbine Peaking Unit CEMS project requires the following milestones:

- Installation of emission testing ports on stacks of monitored units
- Purchase and installation of monitoring components
- Implementation of Data Acquisition & Handling Systems (DAHS)
- Compliance Testing & System Certification

FPL has estimated the cost for implementation of the Similar Units LME option for the CAIR Gas Turbine Peaking Unit CEMS at $396,273.

Title 40: Protection of Environment
PART 75—CONTINUOUS EMISSION MONITORING
Subpart B—Monitoring Provisions

Browse Previous

§ 75.19 Optional SO_2, NOX, and CO_2 emissions calculation for low mass emissions (LME) units.

(a) *Applicability and qualification.* (1) For units that meet the requirements of this paragraph (a)(1) and paragraphs (a)(2) and (b) of this section, the low mass emissions excepted methodology in paragraph (c) of this section may be used in lieu of continuous emission monitoring systems or, if applicable, in lieu of excepted methods under appendix D or E to this part, for the purpose of determining hourly heat input and hourly NO_X, SO_2, and CO_2mass emissions under this part.

(i) A low mass emissions unit is an affected unit that is gas-fired, or oil-fired (as defined in §72.2 of this chapter), and for which:

(A) An initial demonstration is provided, in accordance with paragraph (a)(2) of this section, which shows that the unit emits:

(*1*) No more than 25 tons of SO_2annually and less than 100 tons of NO_Xannually, for Acid Rain Program affected units. If the unit is also subject to the provisions of subpart H of this part, no more than 50 of the allowable annual tons of NO_Xmay be emitted during the ozone season; or

(*2*) Less than 100 tons of NO_Xannually *and* no more than 50 tons of NO_Xduring the ozone season, for non-Acid Rain Program units subject to the provisions of subpart H of this part, for which the owner or operator reports emissions data on a year-round basis, in accordance with §75.74(a) or §75.74(b); or

(*3*) No more than 50 tons of NO_Xper ozone season, for non-Acid Rain Program units subject to the provisions of subpart H of this part, for which the owner or operator reports emissions data only during the ozone season, in accordance with §75.74(b); and

(B) An annual demonstration is provided thereafter, using one of the allowable methodologies in paragraph (c) of this section, showing that the low mass emissions unit continues to emit no more than the applicable number of tons of $SO_2$and/or NO_Xspecified in paragraph (a)(1)(i)(A) of this section.

(C) This paragraph, (a)(1)(i)(C), applies only to a unit that is subject to an SO_2emission limitation under the Acid Rain Program, and that combusts a gaseous fuel other than pipeline natural gas or natural gas (as defined in §72.2 of this chapter). The owner or operator of such a unit must quantify the sulfur content and variability of the gaseous fuel by performing the demonstration described in section 2.3.6 of appendix D to this part, in order for the unit to qualify for LME unit status. If the results of that demonstration show that the gaseous fuel qualifies under paragraph (b) of section 2.3.6 to use a default SO_2emission rate to report SO_2mass emissions under this part, the unit is eligible for LME unit status.

(ii) Each qualifying LME unit must start using the low mass emissions excepted methodology as follows:

(A) For a unit that reports emission data on a year-round basis, begin using the methodology in the first unit operating hour in the calendar year designated in the certification application as the first year that the methodology will be used; or

(B) For a unit that is subject to Subpart H of this part and that reports only during the ozone season according to §75.74(c), begin using the methodology in the first unit operating hour in the ozone season designated in the certification application as the first ozone season that the methodology will be used.

(C) For a new or newly-affected unit, see paragraph (b)(4) of this section for additional guidance.

(2) A unit may initially qualify as a low mass emissions unit if the designated representative submits a certification application to use the LME methodology (as described in §75.53(a)(1)(ii) and in this paragraph, (a)(2)) and the Administrator (or permitting authority, as applicable) certifies the use of such methodology. The certification application shall be submitted no later than 45 days prior to the date on which use of the low mass emissions methodology is expected to commence, and the application must contain:

(i) A statement identifying the projected date on which the LME methodology will first be used. The projected commencement date shall be consistent with paragraphs (a)(1)(ii) and (b)(4) of this section, as applicable; and

(ii) Either:

(A) Actual SO_2 and/or NO_X mass emissions data (as applicable) for each of the three calendar years (or ozone seasons) prior to the calendar year in which the certification application is submitted demonstrating to the satisfaction of the Administrator or (if applicable) the permitting authority, that the unit emitted less than the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section. For the purposes of this paragraph, (a)(2)(ii)(A), the required actual SO_2 or NO_X mass emissions for each qualifying year or ozone season shall be determined using the SO_2, NO_X and heat input data reported to the Administrator in the electronic quarterly reports required under §75.64 or under the Ozone Transport Commission (OTC) NO_X Budget Trading Program. Notwithstanding this requirement, in the absence of such electronic reports, an estimate of the actual emissions for each of the previous three years (or ozone seasons) shall be provided, using either the maximum rated heat input methodology described in paragraph (c)(3)(i) of this section or procedures consistent with the long term fuel flow heat input methodology described in paragraph (c)(3)(ii) of this section, in conjunction with the appropriate SO_2 or NO_X emission rate from paragraph (c)(1)(i) of this section for SO_2, and paragraph (c)(1)(ii) or (c)(1)(iv) of this section for NO_X. Alternatively, the initial estimate of the NO_X emission rate may be based on historical emission test data that is representative of operation at normal load or historical data from a CEMS certified under part 60 of this chapter or under a state CEM program; or

(B) When the three full years (or ozone seasons) of actual SO_2 and NO_X mass emissions data (or reliable estimates thereof) described under paragraph (a)(2)(ii)(A) of this section do not exist, the designated representative may submit an application to use the low mass emissions excepted methodology based upon a combination of actual historical SO_2 and NO_X mass emissions data and projected SO_2 and NO_X mass emissions, totaling three years (or ozone seasons). Except as provided in paragraph (a)(3) of this section, actual data must be used for any years (or ozone seasons) in which such data exists and projected data should be used for any remaining future years (or ozone seasons) needed to provide emissions data for three consecutive calender years (or ozone seasons). For example, if a unit commenced operation two years ago, the designated representative may submit actual, historical data for the previous two years and one year of projected emissions for the current calendar year or, for a new unit, the designated representative may submit three years of projected emissions, beginning with the current calendar year. Any actual or projected annual emissions must demonstrate to the satisfaction of the Administrator that the unit will emit less than the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section. Projected emissions shall be calculated using either the appropriate default emission rates from paragraphs (c)(1)(i) and (c)(1)(ii) of this section (or, alternatively for NO_X, a conservative estimate of the NO_X emission rate, as described in paragraph (a)(4) of this section), in conjunction with projections of unit operating hours or fuel type and fuel usage, according to one of the allowable calculation methodologies in paragraph (c) of this section; and

(iii) A description of the methodology from paragraph (c) of this section that will be used to demonstrate

on-going compliance under paragraph (b) of this section; and

(iv) Appropriate documentation demonstrating that the unit is eligible to use projected emissions to qualify for LME status under paragraph (a)(3) of this section (if applicable).

(3) In the following circumstances, projected emissions for a future year (or years) may be used in lieu of the actual emissions data from one (or more) of the three years (or ozone seasons) preceding the year of the certification application:

(i) If the owner or operator takes an enforceable permit restriction on the number of annual or ozone season unit operating hours for the future year (or years), such that the unit will emit no more than the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section; or

(ii) If the actual emissions for one (or more) of the three years (or ozone seasons) prior to the year of the certification application is not representative of the present and expected future emissions from the unit, because the owner or operator has recently installed emission controls on the unit.

(4) When the owner or operator elects to demonstrate initial LME qualification and on-going compliance using a fuel-and-unit-specific NO_X emission rate in accordance with paragraph (c)(1)(iv) of this section, there will be instances (e.g., for a new or newly-affected unit) where it is not possible to determine that NO_X emission rate prior to submitting the certification application. In such cases, if the generic default NO_X emission rates in Table LM–2 of this section are inappropriately high for the unit, the owner or operator may use a more representative, but conservatively high estimate of the expected NO_X emission rate, for the purposes of the initial monitoring plan submittal and to calculate the unit's projected annual or ozone season emissions under paragraph (a)(2)(ii)(B) of this section. For example, the NO_X emission rate could, as described in paragraph (a)(2)(ii)(A) of this section, be estimated using historical CEM data or historical emission test data that is representative of operation at normal load. The NO_X emission limit specified in the operating permit for the unit could also be used to estimate the NO_X emission rate (except for units equipped with SCR or SNCR), or, consistent with paragraph (c)(1)(iv)(C)(*4*) of this section, for a unit that uses SCR or SNCR to control NO_X emissions, an estimated default NO_X emission rate of 0.15 lb/mmBtu could be used. However, these estimated NO_X emission rates may not be used for reporting purposes in the time period extending from the first hour in which the LME methodology is used to the date and hour on which the fuel-and-unit-specific NO_X emission rate testing is completed. Rather, in that interval, the owner or operator shall either report the appropriate default NO_X emission rate from Table LM–2, or shall report the maximum potential NO_X emission rate, calculated in accordance with §72.2 of this chapter and section 2.1.2.1 of appendix A to this part. Then, beginning with the first unit operating hour after completion of the tests, the appropriate default NO_X emission rate (s) obtained from the fuel-and-unit-specific testing shall be used for emissions reporting.

(b) *On-going qualification and disqualification.* (1) Once a low mass emissions unit has qualified for and has started using the low mass emissions excepted methodology, an annual demonstration is required, showing that the unit continues to emit no more than the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section. The calculation methodology used for the annual demonstration shall be the methodology described in the certification application under paragraph (a)(2)(*iii*) of this section.

(2) If any low mass emissions unit fails to provide the required annual demonstration under paragraph (b)(1) of this section, such that the calculated cumulative emissions for the unit exceed the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section at the end of any calendar year or ozone season, then:

(*i*) *The low mass emissions unit shall be disqualified from using the low mass emissions excepted* methodology; and

(ii) The owner or operator of the low mass emissions unit shall install and certify monitoring systems that meet the requirements of §§75.11, 75.12, and 75.13, and shall report SO_2 (Acid Rain Program units, only), NO_X, and CO_2 (Acid Rain Program units, only) emissions data and heat input data from such monitoring systems by December 31 of the calendar year following the year in which the unit exceeded

the number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section; and

(iii) If the required monitoring systems have not been installed and certified by the applicable deadline in paragraph (b)(2)(ii) of this section, the owner or operator shall report the following values for each unit operating hour, beginning with the first operating hour after the deadline and continuing until the monitoring systems have been provisionally certified: the maximum potential hourly heat input for the unit, as defined in §72.2 of this chapter; the SO_2 emissions, in lb/hr, calculated using the applicable default SO_2 emission rate from paragraph (c)(1)(ii) of this section and the maximum potential hourly unit heat input; the CO_2 emissions, in tons/hr, calculated using the applicable default CO_2 emission rate from paragraph (c)(1)(iii) of this section and the maximum potential hourly unit heat input; and the maximum potential NO_X emission rate, as defined in §72.2 of this chapter.

(3) If a low mass emissions unit that initially qualifies to use the low mass emissions excepted methodology under this section changes fuels, such that a fuel other than those allowed for use in the low mass emissions methodology is combusted in the unit, the unit shall be disqualified from using the low mass emissions excepted methodology as of the first hour that the new fuel is combusted in the unit. The owner or operator shall install and certify SO_2 (Acid Rain Program units, only), NO_X, and CO_2 (Acid Rain Program units, only) and flow (if necessary) monitoring systems that meet the requirements of §§75.11, 75.12, and 75.13 prior to a change to such fuel, and shall report emissions data from such monitoring systems beginning with the date and hour on which the new fuel is first combusted in the unit. *If the required monitoring systems are not installed and certified prior to the fuel switch, the owner or* operator shall report (as applicable) the maximum potential concentration of SO_2, CO_2 and NO_X, the maximum potential NO_X emission rate, the maximum potential flowrate, the maximum potential hourly heat input and the maximum (or minimum, if appropriate) potential moisture percentage, from the date and hour of the fuel switch until the monitoring systems are certified or until probationary calibration error tests of the monitors are passed and the conditional data validation procedures in §75.20(b)(3) begin to be used. All maximum and minimum potential values shall be specific to the new fuel and shall be determined in a manner consistent with section 2 of appendix A to this part and §72.2 of this chapter. *The owner or operator must notify the Administrator (or the permitting authority) in the case where a unit* switches fuels without previously having installed and certified a SO_2, NO_X and CO_2 monitoring system meeting the requirements of §§75.11, 75.12, and 75.13.

(4) If a new of newly-affected unit initially qualifies to use the low mass emissions excepted methodology under this section and the owner or operator wants to use the low mass emissions methodology for the unit, he or she must:

(i) Keep the records specified in paragraph (c)(2) of this section, beginning with the date and hour of commencement of commercial operation, for a new unit subject to an Acid Rain emission limitation, and beginning with the date and hour of the commencement of operation, for a new unit subject to a NO_X mass reduction program under subpart H of this part. For newly-affected units, the records in paragraph (c)(2) of this section shall be kept as follows:

(A) For Acid Rain Program units, begin keeping the records as of the first hour of commercial operation of the unit following the date on which the unit becomes affected; or

(B) For units subject to a NO_X mass reduction program under subpart H of this part, begin keeping the records as of the first hour of unit operation following the date on which the unit becomes an affected unit;

(ii) Use these records to determine the cumulative heat input and SO_2, CO_2, and/or NO_X mass emissions in order to continue to qualify as a low mass emissions unit; and

(iii) Determine the cumulative SO_2 and/or NO_X mass emissions according to paragraph (c) of this section using the same procedures used after the certification deadline for the unit, for purposes of demonstrating eligibility to use the excepted methodology set forth in this section. For example, use the default emission rates in Tables LM–1, LM–2, and LM–3 of this section or use the fuel-and-unit-specific NO_X emission rate determined according to paragraph (c)(1)(iv) of this section. For Acid Rain Program LME units, the Administrator will not count SO_2 mass emissions calculated for the period between commencement of commercial operation and the certification deadline for the unit under §75.4 against

SO_2 allowances to be held in the unit account.

(5) A low mass emissions unit that has been disqualified from using the low mass emissions excepted methodology may subsequently submit an application to qualify again to use the low mass emissions methodology under paragraph (a)(2) of this section only if, following the non-compliant year (or ozone season), at least three full years (or ozone seasons) of actual, monitored emissions data is obtained showing that the unit emitted no more than the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section. Further, the designated representative or authorized account representative must certify in the application that the unit operation for the years or ozone seasons for which the emissions were monitored are representative of the projected future operation of the unit.

(c) *Low mass emissions excepted methodology, calculations, and values* —(1) *Determination of SO 2, NO X, and CO 2 emission rates.* (i) If the unit combusts only natural gas and/or fuel oil, use Table LM–1 of this section to determine the appropriate SO_2 emission rate for use in calculating hourly SO_2 mass emissions under this section (Acid Rain Program units, only). If the unit combusts gaseous fuel(s) other than natural gas, the owner or operator shall use the procedures in section 2.3.6 of appendix D to this part to document the total sulfur content of each such fuel and to determine the appropriate default SO_2 emission rate for each such fuel.

(ii) If the unit combusts only natural gas and/or fuel oil, use either the appropriate NO_X emission factor from Table LM–2 of this section, or a fuel-and-unit-specific NO_X emission rate determined according to paragraph (c)(1)(iv) of this section, to calculate hourly NO_X mass emissions under this section. If the unit combusts a gaseous fuel other than pipeline natural gas or natural gas, the owner or operator shall *determine a fuel-and-unit-specific* NO_X *emission rate according to paragraph (c)(1)(iv) of this section.*

(iii) If the unit combusts only natural gas and/or fuel oil, use Table LM–3 of this section to determine the appropriate CO_2 emission rate for use in calculating hourly CO_2 mass emissions under this section (Acid Rain Program units, only). If the unit combusts a gaseous fuel other than pipeline natural gas or natural gas, the owner or operator shall determine a fuel-and-unit-specific CO_2 emission rate for the fuel, as follows:

(A) Derive a carbon-based F-factor for the fuel, using fuel sampling and analysis, as described in section 3.3.6 of appendix F to this part; and

(B) Use Equation G–4 in appendix G to this part to derive the default CO_2 emission rate. Rearrange the equation, solving it for the ratio of W_{CO2}/H (this ratio will yield an emission rate, in units of tons/mmBtu). Then, substitute the carbon-based F-factor determined in paragraph (c)(1)(iii)(A) of this section into the rearranged equation to determine the default CO_2 emission rate for the unit.

(iv) In lieu of using the default NO_X emission rate from Table LM–2 of this section, the owner or operator may, for each fuel combusted by a low mass emissions unit, determine a fuel-and-unit-specific NO_X emission rate for the purpose of calculating NO_X mass emissions under this section. This option may be used by any unit which qualifies to use the low mass emission excepted methodology under paragraph (a) of this section, and also by groups of units which combust fuel from a common source of supply and which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section to determine heat input. The testing must be completed in a timely manner, such that the test results are reported electronically no later than the end of the calendar year or ozone season in which the LME methodology is first used. If this option is chosen, the following procedures shall be used.

(A) Except as otherwise provided in paragraphs (c)(1)(iv)(F), (c)(1)(iv)(G), and (c)(1)(iv)(I) of this section, determine a fuel-and-unit-specific NO_X emission rate by conducting a four load NO_X emission rate test procedure as specified in section 2.1 of appendix E to this part, for each type of fuel combusted in the unit. For a group of units sharing a common fuel supply, the appendix E testing must be performed on each individual unit in the group, unless some or all of the units in the group belong to an identical group of units, as defined in paragraph (c)(1)(iv)(B) of this section, in which case, representative testing may be conducted on units in the identical group of units, as described in paragraph (c)(1)(iv)(B) of this section. For the purposes of this section, make the following modifications to the appendix E test procedures:

(*1*) Do not measure the heat input as required under 2.1.3 of appendix E to this part.

(*2*) Do not plot the test results as specified under 2.1.6 of appendix E to this part.

(*3*) When using Method 20 for turbines do not correct the NO_X concentration to 15% O_2.

(*4*) If the testing is performed on an uncontrolled diffusion flame turbine, a correction to the observed average NO_X concentration from each run of the Method 20 test must be applied using the following Equation LM–1a.

$$NO_{X_{corr}} = NO_{X_{obs}} \left(\frac{P_r}{P_o}\right)^{0.5} e^{19(H_o - H_r)} \left(\frac{T_r}{T_a}\right)^{1.53} \qquad (Eq.\ LM\text{-}1a)$$

Where:

NO_Xcorr= Corrected NO_X concentration (ppm).

NO_Xobs= Average measured NO_X concentration for each run of the Method 20 test (ppm).

P_r= Average annual atmospheric pressure (or average ozone season atmospheric pressure for a Subpart H unit that reports data only during the ozone season) at the nearest weather station (e.g., a standardized NOAA weather station located at the airport) for the year (or ozone season) prior to the year of the test (mm Hg).

P_o= Observed atmospheric pressure during the test run (mm Hg).

H_r= Average annual atmospheric humidity ratio (or average ozone season humidity ratio for a Subpart H unit that reports data only during the ozone season) at the nearest weather station, for the year (or ozone season) prior to the year of the test (g H_2O/g air).

H_o= Observed humidity ratio during the test run (g H_2O/g air).

T_r= Average annual atmospheric temperature (or average ozone season atmospheric temperature for a Subpart H unit that reports data only during the ozone season) at the nearest weather station, for the year (or ozone season) prior to the year of the test (° K).

T_a= Observed atmospheric temperature during the test run (° K).

(B) Representative appendix E testing may be done on low mass emission units in a group of identical units. All of the units in a group of identical units must combust the same fuel type but do not have to share a common fuel supply.

(*1*) To be considered identical, all low mass emission units must be of the same size (based on maximum rated hourly heat input), manufacturer and model, and must have the same history of modifications (e.g., have the same controls installed, the same types of burners and have undergone major overhauls at the same frequency (based on hours of operation)). Also, under similar operating conditions, the stack or turbine outlet temperature of each unit must be within ±50 degrees Fahrenheit of the average stack or turbine outlet temperature for all of the units.

(*2*) If all of the low mass emission units in the group qualify as identical, then representative testing of the units in the group may be performed according to Table LM–4 of this section.

(*3*) [Reserved]

(*4*) If the acceptance criteria in paragraph (c)(1)(iv)(B)(*1*) of this section are not met then the group of low mass emission units is not considered an identical group of units and individual appendix E testing of each unit is required.

(*5*) Fuel and unit specific NO_X emission rates determined according to paragraphs (c)(1)(iv)(F) and (c)(1)(iv)(G) of this section may be used in lieu of appendix E testing for one or more low mass emission units in a group of identical units.

(C) Based on the results of the part 75 appendix E testing, determine the fuel-and-unit-specific NO_X emission rate as follows:

(*1*) Except for LME units that use selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) to control NO_X emissions, the highest three-run average NO_X emission rate obtained at any load in the appendix E test for a particular type of fuel shall be the fuel-and-unit-specific NO_X emission rate, for that type of fuel.

(*2*) [Reserved]

(*3*) For a group of identical low mass emissions units (except for units that use SCR or SNCR to control NO_X emissions), the fuel-and-unit-specific NO_X emission rate for all units in the group, for a particular type of fuel, shall be the highest three-run average NO_X emission rate obtained at any tested load from any unit tested in the group, for that type of fuel.

(*4*) Except as provided in paragraphs (c)(1)(iv)(C)(*7*) and (c)(1)(iv)(C)(*8*) of this section, for an individual low mass emissions unit which uses SCR or SNCR to control NO_X emissions, the fuel-and-unit-specific NO_X emission rate for each type of fuel combusted in the unit shall be the higher of:

(*i*) The highest three-run average emission rate from any load of the appendix E test for that type of fuel; or

(*ii*) 0.15 lb/mmBtu.

(*5*) [Reserved]

(*6*) Except as provided in paragraphs (c)(1)(iv)(C)(*7*) and (c)(1)(iv)(C)(*8*) of this section, for a group of identical low mass emissions units that are all equipped with SCR or SNCR to control NO_X emissions, the fuel-and-unit-specific NO_X emission rate for each unit in the group of units, for a particular type of fuel, shall be the higher of:

(*i*) The highest three-run average NO_X emission rate at any load from all appendix E tests of all tested units in the group, for that type of fuel; or

(*ii*) 0.15 lb/mmBtu.

(*7*) Notwithstanding the requirements of paragraphs (c)(1)(iv)(C)(*4*) and (c)(1)(iv)(C)(*6*) of this section, for a unit (or group of identical units) equipped with SCR (or SNCR) *and* water (or steam) injection to control NO_X emissions:

(*i*) If the appendix E testing is performed when the water (or steam) injection is in use *and* either upstream of the SCR or SNCR or during a time period when the SCR or SNCR is out of service; then

(*ii*) The highest three-run average emission rate from the appendix E testing may be used as the fuel-and-unit-specific NO_X emission rate for the unit (or, if applicable, for each unit in the group), for each unit operating hour in which the water-to-fuel ratio is within the acceptable range established during the appendix E testing.

(*8*) Notwithstanding the requirements of paragraphs (c)(1)(iv)(C)(*4*) and (c)(1)(iv)(C)(*6*) of this

section, for a unit (or group of identical units) equipped with SCR (or SNCR) *and* uses dry low-NO_X technology to control NO_X emissions:

(*i*) If the appendix E testing is performed during a time period when the dry low-NO_X controls are in use, but the SCR or SNCR is out of service; then

(*ii*) The highest three-run average emission rate from the appendix E testing may be used as the fuel-and-unit-specific NO_X emission rate for the unit (or, if applicable, for each unit in the group), for each unit operating hour in which the parametric data described in paragraph (c)(1)(iv)(H)(*2*) of this section demonstrate that the dry low-NO_X controls are operating in the premixed or low-NO_X mode.

(*9*) For an individual combustion turbine (or a group of identical turbines) that operate principally at base load (or at a set point temperature), but are capable of operating at a higher peak load (or higher internal operating temperature), the fuel-and-unit-specific NO_X emission rate for the unit (or for each unit in the group) shall be as follows:

(*i*) If the testing is done only at base load, use the three-run average NO_X emission rate for base load operating hours and 1.15 times that emission rate for peak load operating hours; or

(*ii*) If the testing is done at both base load and peak load, use the three-run average NO_X emission rate from the base load testing for base load operating hours and the three-run average NO_X emission rate from the peak load testing for peak load operating hours.

(D) For each low mass emissions unit, or group of identical units for which the provisions of paragraph (c)(1)(iv) of this section are used to account for NO_X emission rate, the owner or operator shall determine a new fuel-and-unit-specific NO_X emission rate every five years (20 calendar quarters), unless changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation, or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rate. If such changes occur, the fuel-and-unit-specific NO_X emission rate(s) shall be re-determined according to paragraph (c)(1)(iv) of this section. Testing shall be done at the number of loads specified in paragraph (c)(1)(iv)(A) or (c)(1)(iv)(I) of this section, as applicable. If a low mass emissions unit belongs to a group of identical units and it is required to retest to determine a new fuel-and-unit-specific NO_X emission rate because of changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rate, any other unit in that group of identical units is not required to re-determine the fuel-and-unit-specific NO_X emission rate unless such unit also undergoes changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rates.

(E) Each low mass emissions unit or each low mass emissions unit in a group of identical units for which a fuel-and-unit-specific NO_X emission rate(s) are determined shall meet the quality assurance and quality control provisions of paragraph (e) of this section.

(F) Low mass emission units may use the results of appendix E testing, if such test results are available from a test conducted no more than five years prior to the time of initial certification, to determine the appropriate fuel-and-unit-specific NO_X emission rate(s). However, fuel-and-unit-specific NO_X emission rates from historical testing may not be used longer than five years after the appendix E testing was conducted.

(G) Low mass emissions units for which at least 3 years of quality-assured NO_X emission rate data from a NO_X-diluent CEMS and corresponding fuel usage data are available may determine fuel-and-unit-specific NO_X emission rates from the actual data using the following procedure. Separate the actual NO_X emission rate data into groups, according to the type of fuel combusted. Discard data from periods when multiple fuels were combusted. Each fuel-specific data set must contain at least 168 hours of data and must represent all normal operating ranges of the unit when combusting the fuel. Sort the data in each fuel-specific data set in ascending order according to NO_X emission rate. Determine the 95th

percentile NO_X emission rate for each data set as defined in §72.2 of this chapter. Use the 95th percentile value for each data set as the fuel-and-unit-specific NO_X emission rate, except that for a unit that uses SCR or SNCR for NO_X emission control, if the 95th percentile value is less than 0.15 lb/mmBtu, a value of 0.15 lb/mmBtu shall be used as the fuel-and-unit-specific NO_X emission rate.

(H) For low mass emission units with add-on NO_X emission controls, and for units that use dry low-NO_X technology, the owner or operator shall, during every hour of unit operation during the test period, monitor and record parameters, as required under paragraph (e)(5) of this section, which indicate that the NO_X emission controls are operating properly. After the test period, these same parameters shall be monitored and recorded and kept for all operating hours in order to determine whether the NO_X controls are operating properly and to allow the determination of the correct NO_X emission rate as required under paragraph (c)(1)(iv) of this section.

(1) For low mass emission units with steam or water injection, the steam-to-fuel or water-to-fuel ratio used during the testing must be documented. The water-to-fuel or steam-to-fuel ratio must be maintained during unit operations for a unit to use the fuel and unit specific NO_X emission rate determined during the test. Owners or operators must include in the monitoring plan the acceptable range of the water-to-fuel or steam-to-fuel ratio, which will be used to indicate hourly, proper operation of the NO_X controls for each unit. The water-to-fuel or steam-to-fuel ratio shall be monitored and recorded during each hour of unit operation. If the water-to-fuel or steam-to-fuel ratio is not within the acceptable range in a given hour the fuel and unit specific NO_X emission rate may not be used for that hour, and the appropriate default NO_X emission rate from Table LM–2 shall be reported instead.

(2) For a low mass emissions unit that uses dry low-NO_X premix technology to control NO_X emissions, proper operation of the emission controls means that the unit is in the low-NO_X or premixed combustion mode, and fired with natural gas. Evidence of operation in the low-NO_X or premixed mode shall be provided by monitoring the appropriate turbine operating parameters. These parameters may include percentage of full load, turbine exhaust temperature, combustion reference temperature, compressor discharge pressure, fuel and air valve positions, dynamic pressure pulsations, internal guide vane (IGV) position, and flame detection or flame scanner condition. The acceptable values and ranges for all parameters monitored shall be specified in the monitoring plan for the unit, and the parameters shall be monitored during each subsequent operating hour. If one or more of these parameters is not within the acceptable range or at an acceptable value in a given operating hour, the fuel-and-unit-specific NO_X emission rate may not be used for that hour, and the appropriate default NO_X emission rate from Table LM–2 shall be reported instead. When the unit is fired with oil the appropriate default value from Table LM–2 shall be reported.

(3) For low mass emission units with other types of add-on NO_X controls, appropriate parameters and the acceptable range of the parameters which indicate hourly proper operation of the NO_X controls must be specified in the monitoring plan. These parameters shall be monitored during each subsequent operating hour. If any of these parameters are not within the acceptable range in a given operating hour, the fuel and unit specific NO_X emission rates may not be used in that hour, and the appropriate default NO_X emission rate from Table LM–2 shall be reported instead.

(I) Notwithstanding the requirements in paragraph (c)(1)(iv)(A) of this section, the appendix E testing to determine (or re-determine) the fuel-specific, unit-specific NO_X emission rate for a unit (or for each unit in a group of identical units) may be performed at fewer than four loads, under the following circumstances:

(1) Testing may be done at one load level if the data analysis described in paragraph (c)(1)(iv)(J) of this section is performed and the results show that the unit has operated (or all units in the group of identical units have operated) at a single load level for at least 85.0 percent of all operating hours in the previous three years (12 calendar quarters) prior to the calendar quarter of the appendix E testing. For combustion turbines that are operated to produce approximately constant output (in MW) but which use internal operating and exhaust temperatures and not the actual output in MW to control the operation of the turbine, the internal operating temperature set point may be used as a surrogate for load in demonstrating that the unit qualifies for single-load testing. If the data analysis shows that the unit does not qualify for single-load testing, testing may be done at two (or three) load levels if the unit has operated (or if all units in the group of identical units have operated) cumulatively at two (or three) load

levels for at least 85.0 percent of all operating hours in the previous three years; or

(*2*) If a multiple-load appendix E test was initially performed for a unit (or group of identical units) to determine the fuel-and-unit specific NO_X emission rate, then the periodic retests required under paragraph (c)(1)(iv)(D) of this section may be single-load tests, performed at the load level for which the highest average NO_X emission rate was obtained in the initial test.

(J) To determine whether a unit qualifies for testing at fewer than four loads under paragraph (c)(1)(iv)(I) of this section, follow the procedures in paragraph (c)(1)(iv)(J)(*1*) or (c)(1)(iv)(J)(*2*) of this section, as applicable.

(*1*) Determine the range of operation of the unit, according to section 6.5.2.1 of appendix A to this part. Divide the range of operation into four equal load bands. For example, if the range of operation extends from 20 MW to 100 MW, the four equal load bands would be: band #1: from 20 MW to 40 MW; band #2: from 41 MW to 60 MW; band #3: from 61 MW to 80 MW; and band #4: from 81 to 100 MW. Then, perform a historical load analysis for all unit operating hours in the 12 calendar quarters preceding the quarter of the test. Alternatively, for sources that report emissions data only during the ozone season, the historical load analysis may be based on unit operation in the previous three ozone seasons, rather than unit operation in the previous 12 calendar quarters. Determine the percentage of the data that fall into each load band. For a unit that is not part of a group of identical units, if 85.0% or more of the data fall into one load band, single-load testing may be performed at any point within that load band. For a group of identical units, if each unit in the group meets the 85.0% criterion, then representative single-load testing within the load band may be performed. If the 85.0% criterion cannot be met to qualify for single-load testing but this criterion can be met cumulatively for two (or three) load levels, then testing may be performed at two (or three) loads instead of four.

(*2*) For a combustion turbine that uses exhaust temperature and not the actual output in megawatts to control the operation of the turbine (or for a group of identical units of this type), the owner or operator must document that the unit (or each unit in the group) has operated within ±10% of the set point temperature for 85.0% of the operating hours in the previous 12 calendar quarters to qualify for single-load testing. Alternatively, for sources that report emissions data only during the ozone season, the historical set point temperature analysis may be based on unit operation in the previous three ozone seasons, rather than unit operation in the previous 12 calendar quarters. When the set point temperature is used rather than unit load to justify single-load testing, the designated representative shall certify in the monitoring plan for the unit that this is the normal manner of unit operation and shall document the setpoint temperature.

(2) *Records of operating time, fuel usage, unit output and* NO_X *emission control operating status.* The owner or operator shall keep the following records on-site, for three years, in a form suitable for inspection, except that for unmanned facilities, the records may be kept at a central location, rather than on-site:

(i) For each low mass emissions unit, the owner or operator shall keep hourly records which indicate whether or not the unit operated during each clock hour of each calendar year. The owner or operator may report partial operating hours or may assume that for each hour the unit operated the operating time is a whole hour. Units using partial operating hours and the maximum rated hourly heat input to calculate heat input for each hour must report partial operating hours.

(ii) For each low mass emissions unit, the owner or operator shall keep hourly records indicating the type (s) of fuel(s) combusted in the unit during each hour of unit operation.

(iii) For each low mass emissions unit using the long term fuel flow methodology under paragraph (c)(3)(ii) of this section to determine hourly heat input, the owner or operator shall keep hourly records of unit load (in megawatts or thousands of pounds of steam per hour), for the purpose of apportioning heat input to the individual unit operating hours.

(iv) For each low mass emissions unit with add-on NO_X emission controls of any kind and each unit that uses dry low-NO_X technology, the owner or operator shall keep hourly records of the hourly value of the parameter(s) specified in (c)(1)(iv)(H) of this section used to indicate proper operation of the unit's NO_X controls.

(3) *Heat input.* Hourly, quarterly and annual heat input for a low mass emissions unit shall be determined

using either the maximum rated hourly heat input method under paragraph (c)(3)(i) of this section or the long term fuel flow method under paragraph (c)(3)(ii) of this section.

(i) *Maximum rated hourly heat input method.* (A) For the purposes of the mass emission calculation methodology of paragraph (c)(3) of this section, HI_{hr}, the hourly heat input (mmBtu) to a low mass emissions unit shall be deemed to equal the maximum rated hourly heat input, as defined in §72.2 of this chapter, multiplied by the operating time of the unit for each hour. The owner or operator may choose to record and report partial operating hours or may assume that a unit operated for a whole hour for each hour the unit operated. However, the owner or operator of a unit may petition the Administrator under §75.66 for a lower value for maximum rated hourly heat input than that defined in §72.2 of this chapter. The Administrator may approve such lower value if the owner or operator demonstrates that either the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and such a lower value is representative, of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently.

(B) The quarterly heat input, HI_{qtr}, in mmBtu, shall be determined using Equation LM–1:

$$HI_{qtr} = \sum_{1}^{n} HI_{hr} \qquad (Eq.\ LM\text{-}1)$$

Where:

n = Number of unit operating hours in the quarter.

HI hr= Hourly heat input under paragraph (c)(3)(i)(A) of this section (mmBtu).

(C) The year-to-date cumulative heat input (mmBtu) shall be the sum of the quarterly heat input values for all of the calendar quarters in the year to date.

(D) For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly heat input for the second calendar quarter of the year shall, for compliance purposes, include only the heat input for the months of May and June, and the cumulative ozone season heat input shall be the sum of the heat input values for May, June and the third calendar quarter of the year.

(ii) *Long term fuel flow heat input method.* The owner or operator may, for the purpose of demonstrating that a low mass emissions unit or group of low mass emission units sharing a common fuel supply meets the requirements of this section, use records of long-term fuel flow, to calculate hourly heat input to a low mass emissions unit.

(A) This option may be used for a group of low mass emission units only if:

(1) The low mass emission units combust fuel from a common source of supply; and

(2) Records are kept of the total amount of fuel combusted by the group of low mass emission units and the hourly output (in megawatts or pounds of steam) from each unit in the group; and

(3) All of the units in the group are low mass emission units.

(B) For each fuel used during the quarter, the volume in standard cubic feet (for gas) or gallons (for oil) may be determined using any of the following methods;

(1) Fuel billing records (for low mass emission units, or groups of low mass emission units, which purchase fuel from non-affiliated sources);

(2) American Petroleum Institute (API) standard, American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992

(reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1997, October 1992) (incorporated by reference under §75.6); or;

(*3*) A fuel flow meter certified and maintained according to appendix D to this part.

(C) Except as provided in paragraph (c)(3)(ii)(C)(*3*) of this section, for each fuel combusted during a quarter, the gross calorific value of the fuel shall be determined by either:

(*1*) Using the applicable procedures for gas and oil analysis in sections 2.2 and 2.3 of appendix D to this part. If this option is chosen the highest gross calorific value recorded during the previous calendar year shall be used (or, for a new or newly-affected unit, if there are no sample results from the previous year, use the highest GCV from the samples taken in the current year); or

(*2*) Using the appropriate default gross calorific value listed in Table LM–6 of this section.

(*3*) For gaseous fuels other than pipeline natural gas or natural gas, the GCV sampling frequency shall be daily unless the results of a demonstration under section 2.3.5 of appendix D to this part show that the fuel has a low GCV variability and qualifies for monthly sampling. If daily GCV sampling is required, use the highest GCV obtained in the calendar quarter as GCV_{max} in Equation LM–3, of this section.

(D) If Eq. LM–2 is used for heat input determination, the specific gravity of each type of fuel oil combusted during the quarter shall be determined either by:

(*1*) Using the procedures in section 2.2.6 of appendix D to this part. If this option is chosen, use the highest specific gravity value recorded during the previous calendar year (or, for a new or newly-affected unit, if there are no sample results from the previous year, use the highest specific gravity from the samples taken in the current year); or

(*2*) Using the appropriate default specific gravity value in Table LM–6 of this section.

(E) The quarterly heat input from each type of fuel combusted during the quarter by a low mass emissions unit or group of low mass emissions units sharing a common fuel supply shall be determined using either Equation LM–2 or Equation LM–3 for oil (as applicable to the method used to quantify oil usage) and Equation LM–3 for gaseous fuels. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly heat input for the second calendar quarter of the year shall include only the heat input for the months of May and June.

$$HI_{fuel\text{-}qtr} = M_{qtr} \frac{GCV_{max}}{10^6} \qquad \text{Eq. LM-2 (For fuel oil)}$$

Where:

HI fuel-qtr= Quarterly total heat input from oil (mmBtu).

M_{qtr}= Mass of oil consumed during the quarter, determined as the product of the volume of oil under paragraph (c)(3)(ii)(B) of this section and the specific gravity under paragraph (c)(3)(ii)(D) of this section (lb).

GCV max= Gross calorific value of oil, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/lb)

10^6 = Conversion of Btu to mmBtu.

$$HI_{fuel\text{-}qtr} = Q_{qtr} \frac{GCV_{max}}{10^6} \qquad \text{Eq. LM-3 (for gaseous fuel or fuel oil)}$$

Where:

HI fuel-qtr= Quarterly heat input from gaseous fuel or fuel oil (mmBtu).

Q_{qtr}= Volume of gaseous fuel or fuel oil combusted during the quarter, as determined under paragraph (c)(3)(ii)(B) of this section standard cubic feet (scf) or (gal), as applicable.

GCV_{max}= Gross calorific value of the gaseous fuel or fuel oil combusted during the quarter, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/scf) or (Btu/gal), as applicable.

10^6 = Conversion of Btu to mmBtu.

(F) Use Eq. LM–4 to calculate Hlqtr-total, the quarterly heat input (mmBtu) for all fuels. Hlqtr-totalshall be the sum of the Hlfuel-qtrvalues determined using Equations LM–2 and LM–3.

$$HI_{qtr\text{-}total} = \sum_{all\text{-}fuels} HI_{fuel\text{-}qtr} \qquad (Eq.\ LM\text{-}4)$$

(G) The year-to-date cumulative heat input (mmBtu) for all fuels shall be the sum of all quarterly total heat input (Hlqtr-total) values for all calendar quarters in the year to date. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the cumulative ozone season heat input shall be the sum of the quarterly heat input values for the second and third calendar quarters of the year.

(H) For each low mass emissions unit or each low mass emissions unit in a group of identical units, the owner or operator shall determine the cumulative quarterly unit load in megawatts or thousands of pounds of steam per hour. The quarterly cumulative unit load shall be the sum of the hourly unit load values recorded under paragraph (c)(2) of this section and shall be determined using Equations LM–5 or LM–6. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly cumulative load for the second calendar quarter of the year shall include only the unit loads for the months of May and June.

$$MW_{qtr} = \sum_{all\text{-}hours} MW \qquad Eq.\ LM\text{-}5\ (\text{for MW output})$$

$$ST_{qtr} = \sum_{all\text{-}hours} ST \qquad Eq.\ LM\text{-}6\ (\text{for steam output})$$

Where:

MW_{qtr}=Sum of all unit operating loads recorded during the quarter by the unit (MW).

ST fuel-qtr= Sum of all hourly steam loads recorded during the quarter by the unit (klb of steam/hr).

MW = Unit operating load for a particular unit operating hour (MW).

ST = Unit steam load for a particular unit operating hour (klb of steam/hr).

(I) For a low mass emissions unit that is not included in a group of low mass emission units sharing a common fuel supply, apportion the total heat input for the quarter, Hlqtr-totalto each hour of unit operation using either Equation LM–7 or LM–8:

$$HI_{hr} = HI_{qtr\text{-}total}\frac{MW_{hr}}{MW_{qtr}}$$

(Eq LM–7 for MW output)

$$HI_{hr} = HI_{qtr\text{-}total}\frac{ST_{hr}}{ST_{qtr}}$$

(Eq LM–8 for steam output)

Where:

HI_{hr}= Hourly heat input to the unit (mmBtu).

MW_{hr}= Hourly operating load for the unit (MW).

ST_{hr}= Hourly steam load for the unit (klb of steam/hr).

(J) For each low mass emissions unit that is included in a group of units sharing a common fuel supply, apportion the total heat input for the quarter, HIqtr-totalto each hour of operation using either Equation LM–7a or LM–8a:

$$HI_{hr} = HI_{qtr\text{-}total}\frac{MW_{hr}}{\sum_{all\text{-}units} MW_{qtr}}$$

(Eq LM–7a for MW output)

$$HI_{hr} = HI_{qtr\text{-}total}\frac{ST_{hr}}{\sum_{all\text{-}units} ST_{qtr}}$$

(Eq LM–8a for steam output)

Where:

HI_{hr}= Hourly heat input to the individual unit (mmBtu).

MW_{hr}= Hourly operating load for the individual unit (MW).

ST_{hr}= Hourly steam load for the individual unit (klb of steam/hr).

Σ *MW* qtr= Sum of the quarterly operating

all-units loads (from Eq. LM–5) for all units in the group (MW).

Σ *ST* qtr= Sum of the quarterly steam

all-units loads (from Eq. LM–6) for all units in the group (klb of steam/hr)

(4) *Calculation of SO 2, NO X and CO 2 mass emissions.* The owner or operator shall, for the purpose of demonstrating that a low mass emissions unit meets the requirements of this section, calculate SO_2, NO_X and CO_2 mass emissions in accordance with the following.

(i) *SO 2 mass emissions.* (A) The hourly SO_2 mass emissions (lbs) for a low mass emissions unit (Acid Rain Program units, only) shall be determined using Equation LM–9 and the appropriate fuel-based SO_2 emission factor from Table LM–1 of this section for the fuels combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$W_{SO2} = EF_{SO2} \times HI_{hr}$ (Eq. LM–9)

Where:

W_{SO2} = Hourly SO_2 mass emissions (lbs.)

EF_{SO2} = Either the SO_2 emission factor from Table LM–1 of this section or the fuel-and-unit-specific SO_2 emission rate from paragraph (c)(1)(i) of this section (lb/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input under paragraph (c)(3)(i)(A) of this section or the hourly heat input under paragraph (c)(3)(ii) of this section (mmBtu).

(B) The quarterly SO_2 mass emissions (tons) for the low mass emissions unit shall be the sum of all the hourly SO_2 mass emissions in the quarter, as determined under paragraph (c)(4)(i)(A) of this section, divided by 2000 lb/ton.

(C) The year-to-date cumulative SO_2 mass emissions (tons) for the low mass emissions unit shall be the sum of the quarterly SO_2 mass emissions, as determined under paragraph (c)(4)(i)(B) of this section, for all of the calendar quarters in the year to date.

(ii) *NO X mass emissions.* (A) The hourly NO_X mass emissions for the low mass emissions unit (lbs) shall be determined using Equation LM–10. If more than one fuel is combusted in the hour, use the highest emission rate for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit. For low mass emission units with NO_X emission controls of any kind and for which a fuel-and-unit-specific NO_X emission rate is determined under paragraph (c)(1)(iv) of this section, for any hour in which the parameters under paragraph (c)(1)(iv)(A) of this section do not show that the NO_X emission controls are operating properly, use the NO_X emission rate from Table LM–2 of this section for the fuel combusted during the hour with the highest NO_X emission rate.

$W_{NOX} = EF_{NOX} \times HI_{hr}$ (Eq. LM–10)

Where:

W_{NOX} = Hourly NO_X mass emissions (lbs).

EF_{NOX} = Either the NO_X emission factor from Table LM–2 of this section or the fuel- and unit-specific NO_X emission rate determined under paragraph (c)(1)(iv) of this section (lb/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph(c)(3)(ii) of this section (mmBtu).

(B) The quarterly NO_X mass emissions (tons) for the low mass emissions unit shall be the sum of all of the hourly NO_X mass emissions in the quarter, as determined under paragraph (c)(4)(ii)(A) of this section, divided by 2000 lb/ton.

(C) The year-to-date cumulative NO_X mass emissions (tons) for the low mass emissions unit shall be the sum of the quarterly NO_X mass emissions, as determined under paragraph (c)(4)(ii)(B) of this section, for all of the calendar quarters in the year to date. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the ozone season NO_X mass emissions for the unit shall be the sum of the quarterly NO_X mass emissions, as determined under paragraph (c)(4)(ii)(B) of this section, for the second and third calendar quarters of the year, and the second quarter report shall include emissions data only for May and June.

(iii) *CO 2 Mass Emissions.* (A) The hourly CO_2 mass emissions (tons) for the affected low mass emissions unit (Acid Rain Program units, only) shall be determined using Equation LM–11 and the appropriate fuel-based CO_2 emission factor from Table LM–3 of this section for the fuel being combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$$WCO_2 = EFCO_2 * HI_{rr} \quad \text{(Eq. LM–11)}$$

Where:

WCO_2 = Hourly CO_2 mass emissions (tons).

EF CO2 = Either the fuel-based CO_2 emission factor from Table LM–3 of this section or the fuel-and-unit-specific CO_2 emission rate from paragraph (c)(1)(iii) of this section (tons/mmBtu).

HI_{rr} = Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph (c)(3)(ii) of this section (mmBtu).

(B) The quarterly CO_2 mass emissions (tons) for the low mass emissions unit shall be the sum of all of the hourly CO_2 mass emissions in the quarter, as determined under paragraph (c)(4)(iii)(A) of this section.

(C) The year-to-date cumulative CO_2 mass emissions (tons) for the low mass emissions unit shall be the sum of all of the quarterly CO_2 mass emissions, as determined under paragraph (c)(4)(iii)(B) of this section, for all of the calendar quarters in the year to date.

(d) Each unit that qualifies under this section to use the low mass emissions methodology must follow the recordkeeping and reporting requirements pertaining to low mass emissions units in subparts F and G of this part.

(e) The quality control and quality assurance requirements in §75.21 are not applicable to a low mass emissions unit for which the low mass emissions excepted methodology under paragraph (c) of this section is being used in lieu of a continuous emission monitoring system or an excepted monitoring system under appendix D or E to this part, except for fuel flowmeters used to meet the provisions in paragraph (c)(3)(ii) of this section. However, the owner or operator of a low mass emissions unit shall implement the following quality assurance and quality control provisions:

(1) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use fuel billing records to determine fuel usage, the owner or operator shall keep, at the facility, for three years, the records of the fuel billing statements used for *long term fuel flow determinations.*

(2) For low mass emissions units or groups of units which use the long term fuel flow methodology under

paragraph (c)(3)(ii) of this section and which use one of the methods specified in paragraph (c)(3)(ii)(B)(*2*) of this section to determine fuel usage, the owner or operator shall keep, at the facility, a copy of the standard used and shall keep records, for three years, of all measurements obtained for each quarter using the methodology.

(3) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use a certified fuel flow meter to determine fuel usage, the owner or operator shall comply with the quality control quality assurance requirements for a fuel flow meter under section 2.1.6 of appendix D of this part.

(4) For each low mass emissions unit for which fuel-and-unit-specific NO_X emission rates are determined in accordance with paragraph (c)(1)(iv) of this section, the owner or operator shall keep, at the facility, records which document the results of all NO_X emission rate tests conducted according to appendix E to this part. If CEMS data are used to determine the fuel-and-unit-specific NO_X emission rates under paragraph (c)(1)(iv)(G) of this section, the owner or operator shall keep, at the facility, records of the CEMS data and the data analysis performed to determine a fuel-and-unit-specific NO_X emission rate. The appendix E test records and historical CEMS data records shall be kept until the fuel and unit specific NO_X emission rates are re-determined.

(5) For each low mass emissions unit for which fuel-and-unit-specific NO_X emission rates are determined in accordance with paragraph (c)(1)(iv) of this section and which has add-on NO_X emission controls of any kind or uses dry low-NO_X technology, the owner or operator shall develop and keep on-site a quality assurance plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameters monitored (e.g., water-to-fuel ratio) and the acceptable ranges for each parameter used to determine proper operation of the unit's NO_X controls.

(6) For unmanned facilities, the records required by paragraphs (e)(1), (e)(2) and (e)(4) of this section may be kept at a central location, rather than at the facility.

Table LM–1—SO_2 Emission Factors (lb/mmBtu) for Various Fuel Types

Fuel type	SO_2 emission factors
Pipeline Natural Gas	0.0006 lb/mmBtu.
Other Natural Gas	0.06 lb/mmBtu.
Residual Oil	2.1 lb/mmBtu.
Diesel Fuel	0.5 lb/mmBtu.

Table LM–2—NO_X Emission Rates (lb/mmBtu) for Various Boiler/Fuel Types

Unit type	Fuel type	NO_X emission rate
Turbine	Gas	0.7
Turbine	Oil	1.2
Boiler	Gas	1.5
Boiler	Oil	2

Table LM–3—CO_2 Emission Factors (ton/mmBtu) for Gas and Oil

Fuel type	CO_2 emission factors
Pipeline (or other) Natural Gas	0.059 ton/mmBtu.
Oil	0.081 ton/mmBtu.

Table LM–4—Identical Unit Testing Requirements

Number of identical units in the group	Number of appendix E tests required
2	1
3 to 6	2
7	3
>7	n tests; wheren n = number of units divided by 3 and rounded to nearest integer.

Table LM–5—Default Gross Calorific Values (GCVs) for Various Fuels

Fuel	GCV for use in equation LM–2 or LM–3
Pipeline Natural Gas	1050 Btu/scf.
Other Natural Gas	1100 Btu/scf.
Residual Oil	19,700 Btu/lb or 167,500 Btu/gallon.
Diesel Fuel	20,500 Btu/lb or 151,700 Btu/gallon.

Table LM–6—Default Specific Gravity Values for Fuel Oil

Fuel	Specific gravity (lb/gal)
Residual Oil	8.5
Diesel Fuel	7.4

[63 FR 57500, Oct. 27, 1998, as amended at 64 FR 28592, May 26, 1999; 64 FR 37582, July 12, 1999; 67 FR 40424, 40425, June 12, 2002; 67 FR 53504, Aug. 16, 2002]

Florida Power & Light Company

Clean Air Visibility Rule

**Best Available Retrofit Technology (BART)/
Reasonable Progress Control Technology (RPCT) Project**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI **EXHIBIT** 13
COMPANY Florida Power & Light
WITNESS R. R. LaBauve (RRL-7)
DATE 11-06-07

Project Summary

The results from the BART exemption modeling analysis and the BART Determination Analysis conducted by FPL's consultant , Golder Associates, indicated that FPL's fossil units were exempt with the exception of Turkey Point Fossil Units 1 & 2 which are located adjacent to the Everglades National Park Class 1 area. Final recommendations for BART controls at Turkey Point will be presented to the FDEP based on the analysis results of the five evaluation criteria presented in the final regulations.

In June 2007 FDEP held a Reasonable Progress Rulemaking Workshop to identify reductions which may be required beyond BART. The Department identified 12 of FPL's oil-burning units as Proposed Sources Subject to Reasonable Progress Four-Factor analysis. The Department has initiated new Rulemaking (62-296.341) – "Regional Haze - Reasonable Progress Control Technology (RPCT)" for evaluation of impacts to Class 1 Areas by affected sources. Under the proposed Rule our FPL's sources will have to undergo a 4-factor evaluation for selecting the appropriate control technology to mitigate visibility impacts at one or more Federally Mandated Class 1 Areas, and submit Air Construction permit applications by Jan 31, 2008. Installation of the controls must be in place no later than December 31, 2013.

To determine whether FPL's oil burning units will be affected by the proposed rule, FPL plans to engage a consultant to prepare RPCT analyses required in Rule 62.296.341 Florida Administrative Code (F.A.C.) for FPL facilities identified by Florida Department of Environmental Protection (FDEP). The facilities identified by FDEP are Turkey Point Units 1 and 2, Port Everglades Units 1 through 4, Riviera Units 3 and 4, Martin Units 1 and 2, and Manatee Units 1 and 2. Although Cape Canaveral has not been identified, FDEP has not finalized the rule and the potential exists that this facility may be included.

The scope of work will be a control technology analysis meeting the requirements of 40 Code of Federal Regulations (CFR) Part 51 Appendix Y, Section IV.D. While the rule has not been finalized, recent discussions (7-19-07) with the Trina Vielhauer, Chief of the FDEP Bureau of Air Regulation indicate that air modeling to assess control effectiveness would not be part of the FDEP RPCT evaluation as stated in the EPA regulations. FPL has projected a year 2007 project cost of $25,000 in O&M costs for the required analyses. Exhibit C of this filing discusses FPL's CAVR compliance plan.

BART EXEMPTION MODELING ANALYSIS FOR AFFECTED FPL PLANTS UPDATED APRIL 2007

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April 2007
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INTRODUCTION

Based on comments received from the Florida Department of Environmental Protection (FDEP), the "BART Exemption Modeling Analysis for Affected FPL Plants" report submitted in January 2007 has been revised to include updated particulate matter (PM) emissions for four Florida Power and Light Co. (FPL) plants using the maximum PM emissions measured during annual stack tests performed from 2001 to 2003. Supportive stack test data and maximum heat input rates used for the FPL plants are presented in Appendices B and C. Based on the updated PM emissions, regional haze modeling was performed, which demonstrated that the maximum visibility impairment values for each plant are still predicted to be less than FDEP's Best Available Retrofit Technology (BART) exemption criteria of 0.5 deciview (dv). Therefore, exemptions from BART determination are requested for each of the FPL power plants addressed in this report.

Pursuant to Section 403.061(35), Florida Statutes, the Federal Clean Air Act, and the regional haze regulations contained in Title 40, Part 51 of the Code of Federal Regulations (40 CFR 51), Subpart P – Protection of Visibility, the FDEP is required to ensure that certain sources of visibility impairing pollutants in Florida use BART to reduce the impact of their emissions on regional haze in federal Class I areas. Requirements for individual source BART control technology determinations and for BART exemptions are in Rule 62-296.340 of the Florida Administrative Code (F.A.C.).

Rule 62-296.340(5)(c), F.A.C., states that a BART eligible source may demonstrate that it is exempt from the requirement for BART determination for all pollutants by performing an individual source attribution analysis in accordance with the procedures contained in 40 CFR 51, Appendix Y. A BART-eligible source is exempt from BART determination requirements if its contribution to visibility impairment, as determined below, does not exceed 0.5 dv above natural conditions in any Class I area.

For electric generating units subject to the Clean Air Interstate Rule (CAIR) program, the source attribution analysis need only consider PM emissions (including primary sulfate) for comparison with the contribution threshold.

The 98th percentile, i.e., the 8th highest 24-hour average visibility impairment value in any year or the 22nd highest 24-hour average visibility impairment value over 3 years combined, whichever is higher, is compared to 0.5 dv in the source attribution analysis.

Based on Rule 62-296 340(5)(c), F.A.C., if the owner or operator of a BART-eligible source requests exemption from the requirement for BART determination for all pollutants by submitting its source attribution analysis to the FDEP by January 31, 2007, and the FDEP ultimately grants such exemption, the requirement for submission of an air construction permit application pursuant to 62-296 340(3)(b)1, F.A.C., shall not apply.

This report is submitted to the FDEP to present the source attribution analysis for the following BART-eligible emissions units at the FPL power plants that are BART-eligible sources:

- Cape Canaveral Power Plant - Unit No. 1, Unit No. 2;
- Port Everglades Power Plant - Unit No. 3, Unit No. 4;
- Manatee Power Plant - Unit No. 1, Unit No. 2;
- Martin Power Plant - Unit No. 1,Unit No. 2; and
- Riviera Power Plant - Unit No. 4.

This report contains the following five sections that present a brief source description, visibility modeling methodology, and visibility modeling analysis results for each of the power plants:

- Section A - Cape Canaveral Power Plant;
- Section B - Port Everglades Power Plant;
- Section C - Manatee Power Plant;
- Section D - Martin Power Plant; and
- Section E - Riviera Power Plant.

The objective of the analysis is to demonstrate that these emissions units are exempt from BART determination.

It should be noted that the Turkey Point Power Plant has two BART-eligible units. Because the visibility impacts for these units were predicted to be greater than 0.5 dv, these units are not exempt from BART determination. As a result, a separate report will be submitted for the plant that includes a BART determination analysis.

The source information and methodologies used for the BART exemption analysis are the same as those presented in the document entitled "Air Modeling Protocol to Evaluate Best Available Retrofit Technology (BART) Options for Affected FPL Plants." A copy of this document has been included for reference in Appendix A. The summaries of the annual PM stack emission tests performed for the

FPL power plants are presented in Appendix B. In addition, the maximum heat input rate used to develop the maximum PM emission rate for the affected units at the Port Everglades Power Plant was obtained from the stack test data. The updated PM emission rates that were modeled in the visibility impairment analysis for the Cape Canaveral, Manatee, Martin, and Riviera Power Plants are presented in Appendix C.

SECTION A- CAPE CANAVERAL POWER PLANT

1.0 SOURCE DESCRIPTION

The Cape Canaveral Power Plant (PCC) consists of two oil-fired and natural gas-fired conventional steam electric generating units, designated as Unit No. 1 and Unit No. 2. Each steam unit is a nominal 400 megawatt (MW) class (electric) steam generator that drives a single reheat turbine generator. Both units are best available retrofit technology (BART)-eligible emission units.

PCC is located on the west side of the Indian River, approximately 8 miles north of Cocoa, Florida on U.S. Highway No. 1, Brevard County. An area map showing PCC and prevention of significant deterioration (PSD) Class I areas located within 300 kilometers (km) of PCC is presented in Figure 1-1 of the Protocol. The PSD Class I areas and their distances from the plant are as follows:

- Chassahowitzka National Wilderness Area (NWA) - 182 km;
- Okefenokee NWA - 270 km; and
- Everglades National Park (NP) - 295 km.

The general location of this plant, in Universal Transverse Mercator (UTM) coordinates, is 523.1 km, East; 3,148.7 km, North; Zone 17.

The stack, operating, and particulate matter (PM) emission data, including PM speciation, for the BART-eligible emissions units are presented in detail in the Protocol in Appendix A. The supportive annual PM stack test data from 2001 to 2003 and updated PM emission data used in the modeling are presented in Appendices B and C, respectively.

Because there are minimal fugitive PM emissions and the plant is more than 50 km from the nearest PSD Class I area, fugitive PM emissions from this station were not addressed in the BART evaluation.

Building downwash effects were not considered in the modeling since the distance of the nearest PSD Class I area is more than 50 km from the plant.

2.0 AIR QUALITY MODELING METHODOLOGY

The California Puff (CALPUFF) model, Version 5.756, was used to predict the maximum visibility impairment at the PSD Class I areas located within 300 km of PCC. Recent technical enhancements, including changes to the over-water boundary layer formulation and coastal effects modules (sponsored by the Minerals Management Service), are included in this version. The methods and assumptions used in the CALPUFF model are presented in the Protocol in Appendix A. The 4-km spacing Florida domain was used for the BART exemption. The refined California Meteorology (CALMET) domain used for this modeling analysis has been provided by the Florida Department of Environmental Protection (FDEP). The major features used in preparing these CALMET data have also been described in Section 4.0 of the Protocol.

Currently, the atmospheric light extinction is estimated by an algorithm developed by the Interagency Monitoring of Protected Visual Environments (IMPROVE) committee and adopted by the U.S. Environmental Protection Agency (EPA) under the 1999 Regional Haze Rule (RHR) and referred to in this report as the "1999 IMPROVE algorithm." This algorithm tends to underestimate light extinction for the highest haze conditions and overestimate it for the lowest haze conditions and does not include light extinction due to sea salt, which is important at sites near the seacoasts. As a result of these limitations, the IMPROVE Steering Committee recently developed a new algorithm (the "new IMPROVE algorithm") for estimating light extinction from PM component concentrations, which provides a better correspondence between measured visibility and that calculated from PM component concentrations. A detailed description of the new IMPROVE algorithm and its implementation is presented in Section 3.4 of the Protocol.

The new IMPROVE algorithm will be used if the visibility impairment values predicted with the 1999 IMPROVE algorithm are greater than 0.5 deciview (dv). If the new IMPROVE algorithm is used, the maximum predicted visibility impairment values will be lower than those predicted with the 1999 IMPROVE algorithm.

Visibility impacts were predicted at each PSD Class I area using receptors provided by the National Park Service and are represented in Figures 4-1 through 4-3 of the Protocol.

3.0 AIR QUALITY MODELING METHODOLOGY

Summaries of the updated maximum visibility impairment values for Unit No. 1 and Unit No. 2 at PCC estimated using the 1999 IMPROVE algorithm are presented in Tables A-1 and A-2. The 98th percentile 24-hour average visibility impairment values (i.e., 8th highest) for the years 2001, 2002, and 2003, and the 22nd highest 24-hour average visibility impairment value over the 3 years, are presented in Table A-1. The number of days and receptors for which the visibility impairment was predicted to be greater than 0.5 dv is also presented in Table A-1. The eight highest visibility impairment values predicted for each modeled year at the PSD Class I areas are presented in Table A-2.

As shown in Tables A-1 and A-2, the 8th highest visibility impairment values predicted for each year at all of the PSD Class I areas using the 1999 IMPROVE algorithm are less than 0.5 dv. The 22nd highest visibility impairment values predicted over the 3-year period at the PSD Class I areas are also less than 0.5 dv. As discussed previously, if the new IMPROVE algorithm were used, the maximum predicted visibility impairment values would be lower using the new IMPROVE algorithm than those predicted with the 1999 IMPROVE algorithm.

Based on these results, which demonstrate that the maximum visibility impairment values for Unit No. 1 and Unit No. 2 are predicted to be less than the FDEP's BART exemption criteria of 0.5 dv, an exemption from BART determination is requested for PCC.

The input and output files (excluding CALMET) used for the exemption modeling are provided on a CD submitted with this report. Quality assurance procedures were followed, as described in the Protocol, to ensure that the setup and execution of the CALPUFF model and processing of the modeling results satisfy the regulatory objectives of the BART program.

SECTION B- PORT EVERGLADES POWER PLANT

1.0 SOURCE DESCRIPTION

The Port Everglades Power Plant (PPE) consists of four fossil fuel steam generators and 12 simple-cycle combustion turbines. Two of the steam generators, Unit No. 3 and Unit No. 4, are best available retrofit technology (BART)-eligible emission units. Each of these steam units is a nominal 402-megawatt (MW) class (electric) steam generator that fires natural gas and fuel oil.

PPE is located at 8100 Eisenhower Boulevard, Fort Lauderdale, Broward County. An area map showing PPE and prevention of significant deterioration (PSD) Class I areas located within 300 kilometers (km) of the plant is presented in Figure 1-1 of the Protocol. The only PSD Class I area located within 300 km of the plant is the Everglades National Park (NP), located about 54 km away.

The general location of this plant, in Universal Transverse Mercator (UTM) coordinates, is 587.4 km, East; 2,885.3 km, North; Zone 17.

The stack, operating and particulate matter (PM) emission data, including PM speciation, for the BART-eligible emissions units are presented in detail in the Protocol provided in Appendix A. The supportive annual PM stack test data from 2001 to 2003 that present the maximum heat input rates for each unit are provided in Appendix B. The PM emission rates used in the modeling were based on the permitted PM emission rate and the maximum heat input rate obtained from the stack tests over the 3-year period. As a result, no additional modeling was required based on FDEP's comments.

Because there are minimal fugitive PM emissions and the plant is more than 50 km from the nearest PSD Class I area, fugitive PM emissions from this station were not addressed in the BART evaluation.

Building downwash effects were not considered in the modeling since the distance of the nearest PSD Class I area is more than 50 km from the plant.

2.0 AIR QUALITY MODELING METHODOLOGY

The California Puff (CALPUFF) model, Version 5.756, was used to predict the maximum visibility impairment at the PSD Class I areas located within 300 km of PPE. Recent technical enhancements, including changes to the over-water boundary layer formulation and coastal effects modules (sponsored by the Minerals Management Service), are included in this version. The methods and assumptions used in the CALPUFF model are presented in the Protocol. The 4-km spacing Florida domain was used for the BART exemption. The refined CALMET domain used for this modeling analysis has been provided by the Florida Department of Environmental Protection (FDEP). The major features used in preparing these CALMET data have also been described in Section 4.0 of the Protocol in Appendix A.

Currently, the atmospheric light extinction is estimated by an algorithm developed by the Interagency Monitoring of Protected Visual Environments (IMPROVE) committee, which was adopted by the U.S. Environmental Protection Agency (EPA) under the 1999 Regional Haze Rule (RHR) and referred to in this report as the "1999 IMPROVE algorithm." This algorithm tends to underestimate light extinction for the highest haze conditions and overestimate it for the lowest haze conditions and does not include light extinction due to sea salt, which is important at sites near the seacoasts. As a result of these limitations, the IMPROVE Steering Committee recently developed a new algorithm (the "new IMPROVE algorithm") for estimating light extinction from PM component concentrations, which provides a better correspondence between measured visibility and that calculated from PM component concentrations. A detailed description of the new IMPROVE algorithm and its implementation is presented in Section 3.4 of the Protocol.

The new IMPROVE algorithm will be used if the visibility impairment values predicted with the 1999 IMPROVE algorithm are greater than 0.5 deciview (dv). If the new IMPROVE algorithm is used, the maximum predicted visibility impairment values will be lower than those predicted with the 1999 IMPROVE algorithm.

Visibility impacts were predicted at the PSD Class I area using receptors provided by the National Park Service and are represented in Figure 4-2 of the Protocol.

3.0 AIR QUALITY MODELING METHODOLOGY

Summaries of the maximum visibility impairment values for Unit No 3 and Unit No. 4 at PPE estimated using the 1999 IMPROVE algorithm are presented in Tables B-1 and B-2. The 98th percentile 24-hour average visibility impairment values (i e , 8th highest) for the years 2001, 2002 and 2003, and the 22nd highest 24-hour average visibility impairment value over the 3 years, are presented in Table B-1. The number of days and receptors for which the visibility impairment was predicted to be greater than 0.5 dv is also presented in Table B-1 The eight highest visibility impairment values predicted for each modeled year at the PSD Class I area are presented in Table B-2

As shown in Tables B-1 and B-2, the 8th highest visibility impairment values predicted at the PSD Class I area are 0 59 dv in 2003 while the 22nd highest visibility impairment value predicted over the 3-year period is 0 56 dv. As a result, the visibility impacts were evaluated at the Everglades NP with the new IMPROVE algorithm Similar to the results presented using the 1999 IMPROVE algorithm, summaries of the maximum visibility impairment values estimated using the new IMPROVE algorithm are presented in Tables B-3 and B-4. As shown in Tables B-3 and B-4, the highest 8th highest visibility impairment value predicted at the Everglades NP with the new IMPROVE algorithm is 0 46 dv. The 22nd highest visibility impairment value predicted at this PSD Class I area over the 3-year period is 0 43 dv

Based on these results, which demonstrate that the maximum visibility impairment values for Unit No 3 and Unit No 4 are predicted to be less than the FDEP's BART exemption criteria of 0.5 dv, an exemption from BART determination is requested for PPE

The input and output files (excluding CALMET) used for the exemption modeling are provided on a CD submitted with this report Quality assurance procedures were followed, as described in the Protocol, to ensure that the setup and execution of the CALPUFF model and processing of the modeling results satisfy the regulatory objectives of the BART program.

SECTION C- MANATEE POWER PLANT

1.0 SOURCE DESCRIPTION

The Manatee Power Plant (PMT) consists of two oil-fired and natural gas-fired conventional steam electric generating units, designated as Unit No. 1 and Unit No 2, a "4-on-1" gas-fired combined cycle unit (Unit No 3) and associated support equipment. Each steam unit is a nominal 800-megawatt (MW) class (electric). Both steam units are best available retrofit technology (BART)-eligible emission units.

PMT is located at 19050 State Road 62, Parrish, Manatee County. An area map showing the PMT Plant and prevention of significant deterioration (PSD) Class I areas located within 300 kilometers (km) of the plant is presented in Figure 1-1 of the Protocol. The PSD Class I areas and their distances from the plant are as follows:

- Chassahowitzka National Wilderness Area (NWA) - 116 km; and
- Everglades National Park (NP) - 212 km.

The general location of this plant, in Universal Transverse Mercator (UTM) coordinates, is 367.3 km, East; 3,054.3 km, North; Zone 17.

The stack, operating, and particulate matter (PM) emission data, including PM speciation, for the BART-eligible emissions units are presented in detail in the Protocol in Appendix A. The supportive annual PM stack test data from 2001 to 2003 and updated PM emission data used in the modeling are presented in Appendices B and C, respectively.

Because there are minimal fugitive PM emissions and the plant is more than 50 km from the nearest PSD Class I area, fugitive PM emissions from this station were not addressed in the BART evaluation.

Building downwash effects were not considered in the modeling since the distance of the nearest PSD Class I area is more than 50 km from the plant.

2.0 AIR QUALITY MODELING METHODOLOGY

The California Puff (CALPUFF) model, Version 5 756, was used to predict the maximum visibility impairment at the PSD Class I areas located within 300 km of PMT. Recent technical enhancements, including changes to the over-water boundary layer formulation and coastal effects modules (sponsored by the Minerals Management Service), are included in this version. The methods and assumptions used in the CALPUFF model are presented in the Protocol. The 4-km spacing Florida domain was used for the BART exemption. The refined CALMET domain used for this modeling analysis has been provided by the Florida Department of Environmental Protection (FDEP). The major features used in preparing these CALMET data have also been described in Section 4 0 of the Protocol.

Currently, the atmospheric light extinction is estimated by an algorithm developed by the Interagency Monitoring of Protected Visual Environments (IMPROVE) committee, which was adopted by the EPA under the 1999 Regional Haze Rule (RHR) and referred to in this report as the "1999 IMPROVE algorithm." This algorithm tends to underestimate light extinction for the highest haze conditions and overestimate it for the lowest haze conditions and does not include light extinction due to sea salt, which is important at sites near the seacoasts. As a result of these limitations, the IMPROVE Steering Committee recently developed a new algorithm (the "new IMPROVE algorithm") for estimating light extinction from PM component concentrations, which provides a better correspondence between measured visibility and that calculated from PM component concentrations. A detailed description of the new IMPROVE algorithm and its implementation is presented in Section 3 4 of the Protocol.

The new IMPROVE algorithm will be used if the visibility impairment values predicted with the 1999 IMPROVE algorithm are greater than 0 5 deciview (dv). If the new IMPROVE algorithm is used, the maximum predicted visibility impairment values will be lower than those predicted with the 1999 IMPROVE algorithm.

Visibility impacts were predicted at each PSD Class I area using receptors provided by the National Park Service and are represented in Figures 4-1 through 4-2 of the Protocol.

3.0 AIR QUALITY MODELING METHODOLOGY

Summaries of the updated maximum visibility impairment values for Unit No 1 and Unit No 2 at PMT estimated using the 1999 IMPROVE algorithm are presented in Tables C-1 and C-2. The 98th percentile 24-hour average visibility impairment values (i.e., 8th highest) for the years 2001, 2002, and 2003, and the 22nd highest 24-hour average visibility impairment value over the 3 years, are presented in Table C-1. The number of days and receptors for which the visibility impairment was predicted to be greater than 0.5 dv is also presented in Table C-1. The eight highest visibility impairment values predicted for each modeled year at the PSD Class I areas are presented in Table C-2

As shown in Tables C-1 and C-2, the 8th highest visibility impairment values predicted for each year at all of the PSD Class I areas using the 1999 IMPROVE algorithm are less than 0.5 dv. The 22nd highest visibility impairment values predicted over the 3-year period at the PSD Class I areas are also less than 0.5 dv As discussed previously, if the new IMPROVE algorithm were used, the maximum predicted visibility impairment values would be lower using the new IMPROVE algorithm than those predicted with the 1999 IMPROVE algorithm.

Based on these results, which demonstrate that the maximum visibility impairment values for Unit No. 1 and Unit No. 2 are predicted to be less than the FDEP's BART exemption criteria of 0.5 dv, an exemption from BART determination is requested for PMI.

The input and output files (excluding CALMET) used for the exemption modeling are provided on a CD submitted with this report Quality assurance procedures were followed, as described in the Protocol, to ensure that the setup and execution of the CALPUFF model and processing of the modeling results satisfy the regulatory objectives of the BART program

SECTION D- MARTIN POWER PLANT

1.0 SOURCE DESCRIPTION

The Martin Power Plant (PMR) consists of two oil-fired and natural gas-fired conventional steam-electric generating units, designated as Unit No. 1 and Unit No 2; combined cycle units (Units 3A, 3B, 4A, and 4B) consisting of 170 megawatt (MW) gas turbines matched with heat recovery steam generators (HRSGs) [each pair of gas turbines (3A/3B and 4A/4B) provides steam to a common steam-electrical turbine (160 MW each)]; and two simple cycle gas turbines (Units 8A and 8B), each rated at 170 MW.

Each steam unit is a nominal 863 MW class (electric). Both steam units are best available retrofit technology (BART)-eligible emission units.

PMR is located approximately 7 miles north of Indiantown on State Road 710 and east of Lake Okeechobee in Martin County, Florida. An area map showing PMR and prevention of significant deterioration (PSD) Class I areas located within 300 kilometers (km) of the plant is presented in Figure 1-1 of the Protocol. The PSD Class I areas and their distances from the plant are as follows:

- Chassahowitzka National Wilderness Area (NWA) - 145 km; and
- Everglades National Park (NP) - 267 km

The general location of this plant, in Universal Transverse Mercator (UTM) coordinates, is 543.1 km, East; 2,993.0 km, North; Zone 17.

The stack, operating and particulate matter (PM) emission data, including PM speciation, for the BART-eligible emissions units are presented in detail in the Protocol in Appendix A. The supportive annual PM stack test data from 2001 to 2003 and updated PM emission data used in the modeling are presented in Appendices B and C, respectively.

Because there are minimal fugitive PM emissions and the plant is more than 50 km from the nearest PSD Class I area, fugitive PM emissions from this station were not addressed in the BART evaluation.

Building downwash effects were not considered in the modeling since the distance of the nearest PSD Class I area is more than 50 km from the plant.

2.0 AIR QUALITY MODELING METHODOLOGY

The California Puff (CALPUFF) model, Version 5.756, was used to predict the maximum visibility impairment at the PSD Class I areas located within 300 km of PMR. Recent technical enhancements, including changes to the over-water boundary layer formulation and coastal effects modules (sponsored by the Minerals Management Service), are included in this version. The methods and assumptions used in the CALPUFF model are presented in the Protocol. The 4-km spacing Florida domain was used for the BART exemption. The refined CALMET domain used for this modeling analysis has been provided by the Florida Department of Environmental Protection (FDEP). The major features used in preparing these CALMET data have also been described in Section 4.0 of the Protocol.

Currently, the atmospheric light extinction is estimated by an algorithm developed by the Interagency Monitoring of Protected Visual Environments (IMPROVE) committee, which was adopted by the U.S. Environmental Protection Agency (EPA) under the 1999 Regional Haze Rule (RHR) and referred to in this report as the "1999 IMPROVE algorithm." This algorithm tends to underestimate light extinction for the highest haze conditions and overestimate it for the lowest haze conditions and does not include light extinction due to sea salt, which is important at sites near the seacoasts. As a result of these limitations, the IMPROVE Steering Committee recently developed a new algorithm (the "new IMPROVE algorithm") for estimating light extinction from PM component concentrations, which provides a better correspondence between measured visibility and that calculated from PM component concentrations. A detailed description of the new IMPROVE algorithm and its implementation is presented in Section 3.4 of the Protocol.

The new IMPROVE algorithm will be used if the visibility impairment values predicted with the 1999 IMPROVE algorithm are greater than 0.5 deciview (dv). If the new IMPROVE algorithm is used, the maximum predicted visibility impairment values will be lower than those predicted with the 1999 IMPROVE algorithm.

Visibility impacts were predicted at each PSD Class I area using receptors provided by the National Park Service and are represented in Figures 4-1 through 4-2 of the Protocol.

3.0 AIR QUALITY MODELING METHODOLOGY

Summaries of the updated maximum visibility impairment values for Unit No. 1 and Unit No. 2 at PMR estimated using the 1999 IMPROVE algorithm are presented in Tables D-1 and D-2. The 98th percentile 24-hour average visibility impairment values (i.e., 8th highest) for the years 2001, 2002, and 2003, and the 22nd highest 24-hour average visibility impairment value over the 3 years, are presented in Table D-1. The number of days and receptors for which the visibility impairment was predicted to be greater than 0.5 dv is also presented in Table D-1. The eight highest visibility impairment values predicted for each modeled year at the PSD Class I areas are presented in Table D-2.

As shown in Tables D-1 and D-2, the 8th highest visibility impairment values predicted for each year at all of the PSD Class I areas using the 1999 IMPROVE algorithm are less than 0.5 dv. The 22nd highest visibility impairment values predicted over the 3-year period at the PSD Class I areas are also less than 0.5 dv. As discussed previously, if the new IMPROVE algorithm were used, the maximum predicted visibility impairment values would be lower using the new IMPROVE algorithm than those predicted with the 1999 IMPROVE algorithm.

Based on these results, which demonstrate that the maximum visibility impairment values for Unit No. 1 and Unit No. 2 are predicted to be less than the FDEP's BART exemption criteria of 0.5 dv, an exemption from BART determination is requested for PMR.

The input and output files (excluding CALMET) used for the exemption modeling are provided on a CD submitted with this report. Quality assurance procedures were followed, as described in the Protocol, to ensure that the setup and execution of the CALPUFF model and processing of the modeling results satisfy the regulatory objectives of the BART program.

SECTION E- RIVIERA BEACH POWER PLANT

1.0 SOURCE DESCRIPTION

The Riviera Beach Power Plant (PRV) consists of two oil-fired and natural gas-fired conventional steam electric generating units, designated as Unit No. 3 and Unit No. 4. Each steam unit is a nominal 300 megawatt (MW) class (electric). Unit No. 4 is a best available retrofit technology (BART)-eligible emission unit; Unit No. 3 is not.

PRV is located at 200-300 Broadway, Riviera Beach, Palm Beach County. An area map showing the PRV Plant and prevention of significant deterioration (PSD) Class I areas located within 300 kilometers (km) of the plant is presented in Figure 1-1 of the Protocol. The only PSD Class I area located within 300 km of the plant is the Everglades National Park (NP), located about 122 km away.

The general location of this plant, in Universal Transverse Mercator (UTM) coordinates, is 594.2 km, East; 2,960.7 km, North; Zone 17.

The stack, operating and particulate matter (PM) emission data, including PM speciation, for the BART-eligible emissions units are presented in detail in the Protocol in Appendix A. The supportive annual PM stack test data from 2001 to 2003 and updated PM emission data used in the modeling are presented in Appendices B and C, respectively.

Because there are minimal fugitive PM emissions and the plant is more than 50 km from the nearest PSD Class I area, fugitive PM emissions from this station were not addressed in the BART evaluation.

Building downwash effects were not considered in the modeling since the distance of the nearest PSD Class I area is more than 50 km from the plant.

2.0 AIR QUALITY MODELING METHODOLOGY

The California Puff (CALPUFF) model, Version 5.756, was used to predict the maximum visibility impairment at the PSD Class I areas located within 300 km of PRV. Recent technical enhancements, including changes to the over-water boundary layer formulation and coastal effects modules (sponsored by the Minerals Management Service), are included in this version. The methods and assumptions used in the CALPUFF model are presented in the Protocol. The 4-km spacing Florida domain was used for the BART exemption. The refined CALMET domain used for this modeling analysis has been provided by the Florida Department of Environmental Protection (FDEP). The major features used in preparing these CALMET data have also been described in Section 4.0 of the Protocol.

Currently, the atmospheric light extinction is estimated by an algorithm developed by the Interagency Monitoring of Protected Visual Environments (IMPROVE) committee, which was adopted by the U.S. Environmental Protection Agency (EPA) under the 1999 Regional Haze Rule (RHR) and referred to in this report as the "1999 IMPROVE algorithm." This algorithm tends to underestimate light extinction for the highest haze conditions and overestimate it for the lowest haze conditions and does not include light extinction due to sea salt, which is important at sites near the seacoasts. As a result of these limitations, the IMPROVE Steering Committee recently developed a new algorithm (the "new IMPROVE algorithm") for estimating light extinction from PM component concentrations, which provides a better correspondence between measured visibility and that calculated from PM component concentrations. A detailed description of the new IMPROVE algorithm and its implementation is presented in Section 3.4 of the Protocol.

The new IMPROVE algorithm will be used if the visibility impairment values predicted with the 1999 IMPROVE algorithm are greater than 0.5 deciview (dv). If the new IMPROVE algorithm is used, the maximum predicted visibility impairment values will be lower than those predicted with the 1999 IMPROVE algorithm.

Visibility impacts were predicted at the PSD Class I area using receptors provided by the National Park Service and are represented in Figure 4-2 of the Protocol.

3.0 AIR QUALITY MODELING METHODOLOGY

Summaries of the updated maximum visibility impairment values for Unit No 4 at PRV estimated using the 1999 IMPROVE algorithm are presented in Tables E-1 and E-2. The 98th percentile 24-hour average visibility impairment values (i.e., 8th highest) for the years 2001, 2002 and 2003, and the 22nd highest 24-hour average visibility impairment value over the 3 years, are presented in Table E-1. The number of days and receptors for which the visibility impairment was predicted to be greater than 0.5 dv is also presented in Table E-1. The eight highest visibility impairment values predicted for each modeled year at the PSD Class I area are presented in Table E-2

As shown in Tables E-1 and E-2, the 8th highest visibility impairment values predicted for each year at all of the PSD Class I areas using the 1999 IMPROVE algorithm are less than 0 5 dv. The 22nd highest visibility impairment value predicted over the 3-year period at the PSD Class I area is also less than 0.5 dv. As discussed previously, if the new IMPROVE algorithm were used, the maximum predicted visibility impairment values would be lower using the new IMPROVE algorithm than those predicted with the 1999 IMPROVE algorithm

Based on these results, which demonstrate that the maximum visibility impairment values for Unit No. 4 are predicted to be less than the FDEP's BART exemption criteria of 0 5 dv, an exemption from BART determination is requested for PRV Unit No 4

The input and output files (excluding CALMET) used for the exemption modeling are provided on a CD submitted with this report Quality assurance procedures were followed, as described in the Protocol, to ensure that the setup and execution of the CALPUFF model and processing of the modeling results satisfy the regulatory objectives of the BART program.

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Proposed Reasonable Progress Rule Workshop

Brief Background and Procedure
Public Workshop
June 14, 2007

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Regulatory Requirements

- Clean Air Act – Sections 169A and B
- Federal Rules –
  - Federal Register, Vol. 64, No. 126, Thursday, July 1, 1999 – "Regional Haze Rule"
  - 40 CFR Part 51, Subpart P – Protection of Visibility
- Federal Guidance on Reasonable Progress
  - Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, U.S. EPA, June 1, 2007, rev

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 14
COMPANY Florida Power & Light
WITNESS R.R. LaBauve (RRL-8)
DATE 11-06-07

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National Goal

- "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution."
- Achieve natural visibility conditions within Class I areas by 2064

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Regional Haze Rule - Purpose

- Section 51.300 – ". . . require states to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution ..."

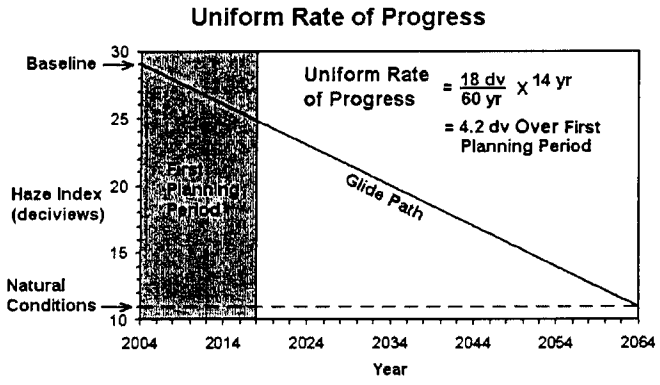
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RH Program Requirements

- State must submit an implementation plan (SIP)
  - Must establish goals (expressed in deciviews) that provide for **reasonable progress** towards achieving natural visibility conditions

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Concept



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Four Factors in Determining the Reasonable Progress Goal

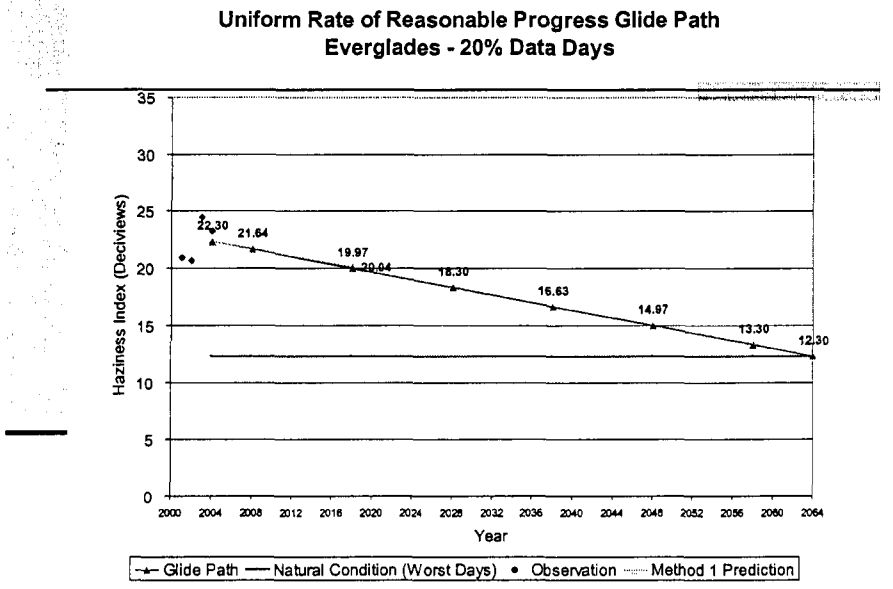
- Cost of compliance
- Time necessary for compliance
- Energy and non-air quality environmental impacts of compliance
- Remaining useful life of any potentially affected sources

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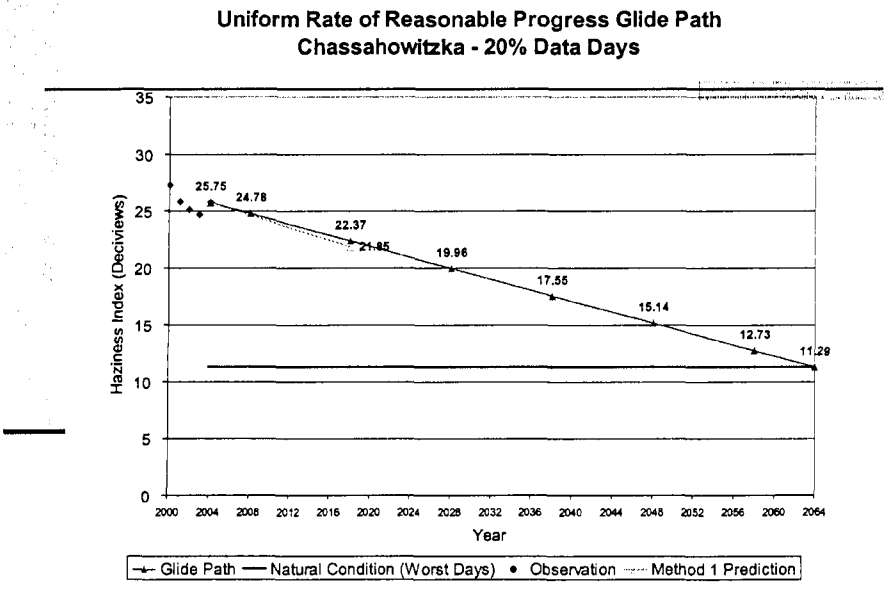
Three Components to Consider

- Evaluation of 2018 visibility considering current or "on the books" requirements for emissions reductions (e.g., CAIR, motor vehicle emissions standards, and many other already commanded reductions). VISTAS has completed this component.
- Regional Haze Rule directed **BART** requirements, section 51.302. Not completed.
- Regional Haze Rule directed **Reasonable Progress** requirement, section 51.308. Subject of this rulemaking.

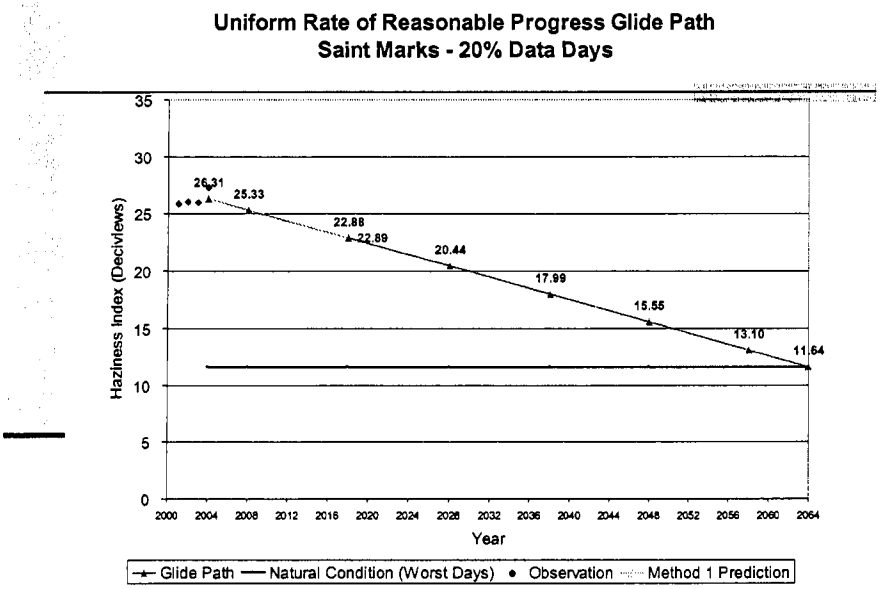
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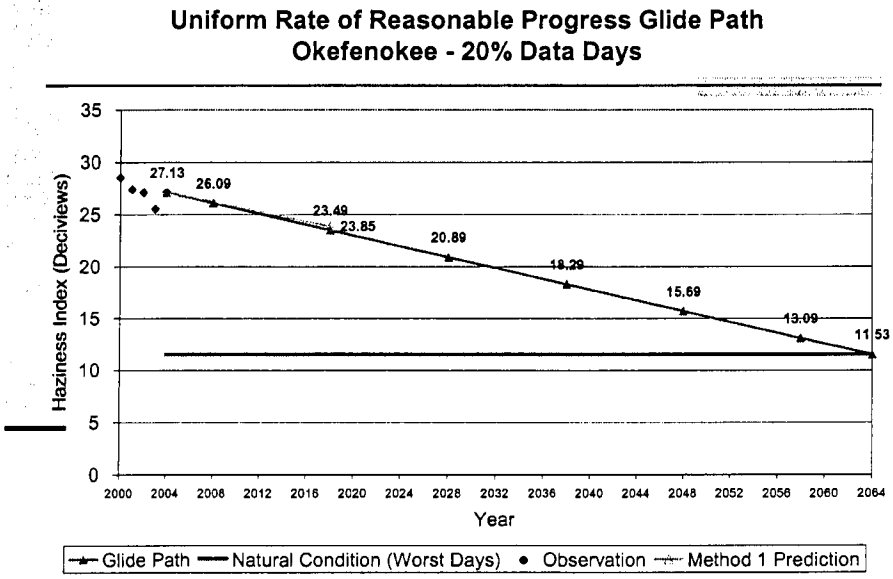
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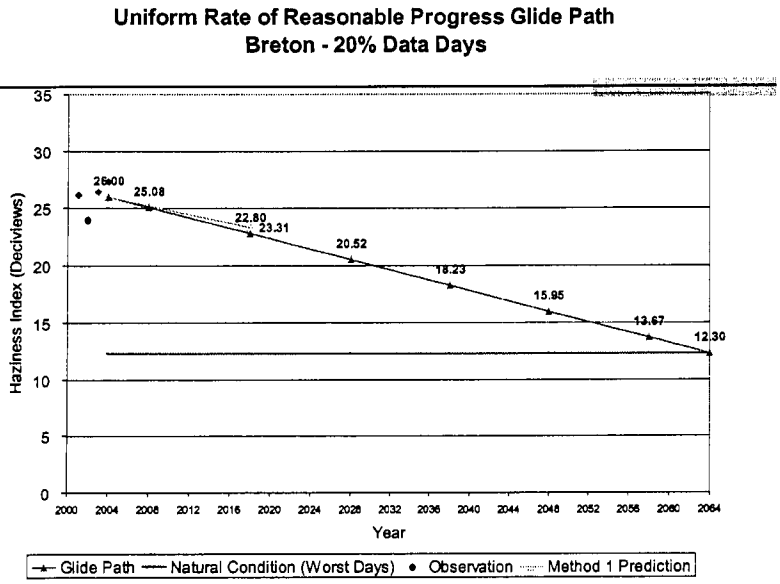
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IPM Projections

- Converts all oil-fired boilers to gas
- Affects sources throughout the state, but largely in South Florida.
- Primary power company (FPL) has indicated no intention of gas-only operation.
- Result, projected glidepaths (esp. Everglades) overly optimistic.

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Plant Name	Point ID	2002 Actual SO2 Emissions (TPY)	2018 VISTAS Projected SO2 Emissions (TPY)
FLORIDA POWER & LIGHT (PPE) PORT EVERGLA	1	3,053	0
	2	3,284	0
	3	6,409	0
	4	6,205	0
FLORIDA POWER & LIGHT (PTF) TURKEY POINT	1	4,327	0
	2	4,610	0
FLORIDA POWER & LIGHT (PMT) MANATEE POWE	1	13,930	0
	2	15,073	0
FLORIDA POWER & LIGHT (PMR) FPL / MARTIN	1	6,886	0
	2	7,803	0
FLORIDA POWER & LIGHT (PRV) RIVIERA POWE	3	4,630	0
	4	4,291	0
PROGRESS ENERGY FLORIDA, INC. ANCLOTE PO	1	13,879	0
	2	13,225	0
PROGRESS ENERGY FLORIDA, INC. BARTOW PLA	1	6,149	0
	2	6,483	0
	3	11,249	0
NORTHSIDE	3	7,146	0
PROGRESS ENERGY FLORIDA, INC. FL POWER S	1	657	0
	2	809	0
	3	740	0

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Applicability of Reasonable Progress

- Applies to all sources and all visibility-impairing pollutants.
- Purpose of this rule is to use the information derived from VISTAS to target the most relevant sources (i.e., pair-down the number of sources and pollutants needed to evaluate for reasonable progress).

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Important Results from VISTAS

- Sulfate is the dominate component of regional haze in the Southeast.
  - Implication – focus on SO2 reductions
- Nearly all of the SO2 emissions are from coal and oil-fired EGU's, and industrial plants.
  - Implication – focus on point source EGUs' and industrial facilities.

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Important Product Produced by VISTAS -- Area of Influence

- VISTAS developed information based on wind trajectories that indicate the likelihood that a source at a given location will impact each Class I area.
- A value (RTmax) is determined for each source location that is proportional to each sources probability that it would impact a particular Class I area on days of poor visibility.

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Proposed Selection Criteria

- Selection based on modified Georgia criteria with RTmax*Q/d:
  - VISTAS residence time data (within 5% for EGU's and 10% non-EGU's)
  - 2002 actual emissions (units > 250 tpy)
  - >= 0.5% unit contribution, considering only Florida units
- Selection based on each Class I area potentially affected by Florida sources (EVER,CHAS,SAMA,OKEF,WOLF,BRET)

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Explanation of Terms

- RTmax -- This term is a metric for the frequency that air flows from the source to the Class I area on days of poor visibility.
- Q – Actual 2002 SO2 emissions in tons per year
- d – Distance (km), this term is a surrogate for dispersion.

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Procedure

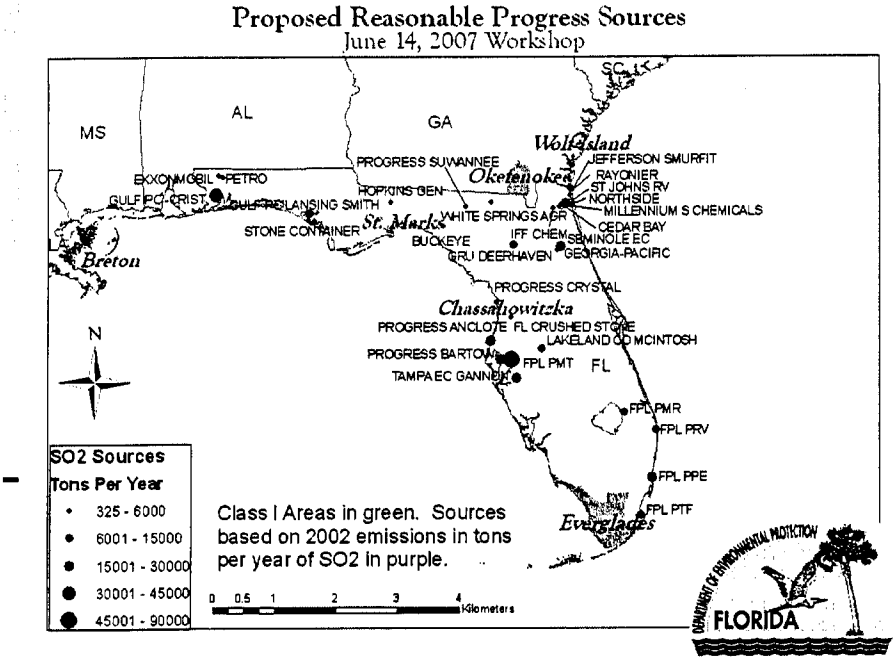
- For each unit with SO2 emissions >=250 tpy, identify all EGU's with an RTmax >=5% and all non-EGU's with an RTmax>=10% for each Class I area.
- For each of these units, calculate RTmax*Q/d for each Class I area.
- For each Class I area, sum RTmax*Q/d over all units and calculate the relative contribution for each unit.
- Select all units that contribute 0.5% or greater.

FDEP Reasonable Further Progress Workshop
Slide 22

Proposed Selection (see handouts)

- 30 Facilities comprising 69 units
  - 17 power plants
  - 4 pulp and paper
  - 9 other (chemical, phosphate,etc.)

FDEP Reasonable Further Progress Workshop
Slide 23



FLORIDA ADMINISTRATIVE WEEKLY UNDER SECTION VI, "NOTICES OF MEETINGS, WORKSHOPS AND PUBLIC HEARINGS."
THE PRELIMINARY TEXT OF THE PROPOSED RULE DEVELOPMENT IS NOT AVAILABLE.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

Notices for the Department of Environmental Protection between December 28, 2001 and June 30, 2006, go to http://www.dep.state.fl.us/ under the link or button titled "Official Notices."

DEPARTMENT OF ENVIRONMENTAL PROTECTION

RULE NO.:	RULE TITLE:
62-296.341	Regional Haze – Reasonable Progress

PURPOSE AND EFFECT: The proposed rule development involves amendments to rule Chapter 62-296, F.A.C., to implement the reasonable progress portion of the U.S. Environmental Protection Agency's (EPA's) regional haze regulations. Pursuant to these regulations, the department is required to ensure that certain sources of visibility-impairing pollutants in Florida limit their emissions such that reasonable progress is made toward the goal of achieving natural visibility conditions in federal Class I areas. New Rule 62-296.341, F.A.C., is created to set forth procedural requirements by which reasonable progress determinations will be made for affected sources. There is no draft rule language available at this time; however, it is expected the department will post draft rule language at the following web site by June 6, 2007: http://www.dep.state.fl.us/Air/rules/regulatory.htm.
SUBJECT AREA TO BE ADDRESSED: The proposed new rule section addresses air permitting and control technology requirements for sources subject to the reasonable progress portion of EPA's regional haze regulations.
SPECIFIC AUTHORITY: 403.061 FS.
LAW IMPLEMENTED: 403.031, 403.061, 403.087 FS.
A RULE DEVELOPMENT WORKSHOP WILL BE HELD AT THE DATE, TIME AND PLACE SHOWN BELOW:
DATE AND TIME: Thursday, June 14, 2007, 10:00 a.m.
PLACE: Department of Environmental Protection, Bob Martinez Center, Room 609, 2600 Blair Stone Rd., Tallahassee, Florida
Pursuant to the provisions of the Americans with Disabilities Act, any person requiring special accommodations to participate in this workshop/meeting is asked to advise the agency at least 48 hours before the workshop/meeting by contacting: Ms. Lynn Scearce, (850)921-9551. If you are hearing or speech impaired, please contact the agency using the Florida Relay Service, 1(800)955-8771 (TDD) or 1(800)955-8770 (Voice).
THE PERSON TO BE CONTACTED REGARDING THE PROPOSED RULE DEVELOPMENT AND A COPY OF THE PRELIMINARY DRAFT, IF AVAILABLE, IS: Mr. Tom Rogers, (850)921-9554 or tom.rogers@dep.state.fl.us
THE PRELIMINARY TEXT OF THE PROPOSED RULE DEVELOPMENT IS NOT AVAILABLE.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

RULE NO.:	RULE TITLE:
62-347.100	Purpose

PURPOSE AND EFFECT: The Department, in coordination with the water management districts, proposes to develop a new Chapter 62-347, F.A.C., to develop updated stormwater quality treatment design and performance standards. These design and performance standards will update the existing criteria and reflect new research on design and performance standards, and particularly today's understanding of the impact of nutrient discharges from surface water management systems on water quality. The goal of the rule is to provide stormwater quality treatment design and performance standards that can be applied state-wide. The proposed rule will apply to new systems.
SUBJECT AREA TO BE ADDRESSED: Develop updated stormwater quality treatment design and performance standards for surface water management systems, with particular emphasis on standards that will reduce nutrient discharges.
SPECIFIC AUTHORITY: 373.026(7), 373.043, 373.418, 403.805(1) FS.
LAW IMPLEMENTED: 373.042, 373.409, 373.413, 373.4142, 373.4145, 373.416, 373.4132, 373.426, 373.429 FS.
IF REQUESTED IN WRITING AND NOT DEEMED UNNECESSARY BY THE AGENCY HEAD, A RULE DEVELOPMENT WORKSHOP WILL BE NOTICED IN THE NEXT AVAILABLE FLORIDA ADMINISTRATIVE WEEKLY.
THE PERSON TO BE CONTACTED REGARDING THE PROPOSED RULE DEVELOPMENT AND A COPY OF THE PRELIMINARY DRAFT, IF AVAILABLE, IS: Alice Heathcock, Florida Department of Environmental Protection, Office of Submerged Lands and Environmental Resources, MS 2500, 2600 Blair Stone Road, Tallahassee, FL 32399-2400, telephone (850)245-8483, or e-mail: Alice.Heathcock@dep.state.fl.us. Further information and updates on this proposed rule also may be obtained from the Department's Web Site at: http://www.dep.state.fl.us/water/wetlands/erp/rules/rulestat.htm. (OGC No. 07-0552)
THE PRELIMINARY TEXT OF THE PROPOSED RULE DEVELOPMENT IS NOT AVAILABLE.

Table C1
FDEP Screening Results for Four-Factor Eligibility

Workshop Draft 6-12-07 - Proposed Sources Subject to Reasonable Progress Four-Factor Analysis

Plant ID	Plant Name	Point ID	2002 Actual SO2 Emissions (TPY)	2018 VISTAS Projected SO2 Emissions (TPY)	SO2 BART Determination	Affected Class I Area(s)
0010006	CITY OF GAINESVILLE, GRU DEERHAVEN GENER	5	6,969	1,062		CHAS,OKEF,SAMA,WOLF
0050009	STONE CONTAINER CORPORATION	1	714	744		SAMA
		15	629	735		SAMA
		16	1,871	2,108		SAMA
		19	687	804		SAMA
0050014	GULF POWER COMPANY LANSING SMITH PLANT	1	6,564	7,351		BRET,SAMA
		2	6,742	8,412		BRET,SAMA
0110036	FLORIDA POWER & LIGHT (PPE) PORT EVERGLA	1	3,053	0		EVER
		2	3,284	0		EVER
		3	6,409	0		EVER
		4	6,205	0		EVER
0170004	PROGRESS ENERGY FLORIDA, INC. CRYSTAL RI	1	18,998	13,536		CHAS,OKEF,SAMA
		2	20,728	15,240		CHAS,OKEF,SAMA
		3	26,436	3,634		CHAS,OKEF,SAMA
		4	24,635	6,119		CHAS,OKEF,SAMA
0250003	FLORIDA POWER & LIGHT (PTF) TURKEY POINT	1	4,327	0		EVER
		2	4,610	0		EVER
0310039	MILLENNIUM SPECIALTY CHEMICALS	6	505	590		OKEF,WOLF
0310045-A	SAINT JOHNS RIVER	16	11,076	5,882		OKEF,SAMA,WOLF
		17	10,185	7,420		OKEF,SAMA,WOLF
0310045-B	NORTHSIDE	26	2,421	2,830		OKEF,WOLF
		27	5,090	5,950		OKEF,SAMA,WOLF
		3	7,146	0		OKEF,SAMA,WOLF
0310071	IFF CHEMICAL HOLDINGS, INC.	3	624	733		OKEF,WOLF
0310337	CEDAR BAY COGENERATION INC.	1	650	742		OKEF,WOLF
		2	641	742		OKEF,WOLF
		3	628	742		OKEF,WOLF
0330045	GULF POWER COMPANY CRIST ELECTRIC GENERA	4	2,464	304		BRET
		5	2,711	277		BRET
		6	10,889	1,242		BRET,SAMA
		7	21,546	4,648		BRET,SAMA
0470002	WHITE SPRINGS AGRICULTURAL CHEMICALS,INC	66	1,140	1,496	Yes	OKEF,SAMA
		67	996	1,308	Yes	OKEF
0530021	FLORIDA CRUSHED STONE CO., INC.	18	2,906	2,884		CHAS,SAMA
0570040	TAMPA ELECTRIC COMPANY F.J. GANNON STATI	1	5,157	0		EVER
		2	4,942	0		EVER
		3	5,602	0		EVER
		4	5,577	0		EVER
		5	8,043	0		EVER,SAMA
		6	16,097	0		CHAS,EVER,SAMA
0730003	CITY OF TALLAHASSEE ARVAH B.HOPKINS GENE	4	325	0		SAMA
0810010	FLORIDA POWER & LIGHT (PMT) MANATEE POWE	1	13,930	0		EVER,SAMA
		2	15,073	0		EVER,SAMA
0850001	FLORIDA POWER & LIGHT (PMR) FPL / MARTIN	1	6,886	0		EVER
		2	7,603	0		EVER
0890003	JEFFERSON SMURFIT CORPORATION (US)	15	3,242	3,639		OKEF,WOLF
		6	257	300		WOLF
0890004	RAYONIER PERFORMANCE FIBERS LLC	6	1,075	1,256		OKEF,WOLF
0990042	FLORIDA POWER & LIGHT (PRV) RIVIERA POWE	3	4,630	0		EVER
		4	4,291	0		EVER
1010017	PROGRESS ENERGY FLORIDA, INC. ANCLOTE PO	1	13,879	0		CHAS,EVER,SAMA
		2	13,225	0		CHAS,EVER,SAMA
1030011	PROGRESS ENERGY FLORIDA, INC. BARTOW PLA	1	6,149	0		EVER,SAMA
		2	6,483	0		EVER,SAMA
		3	11,249	0		EVER,SAMA
1050004	LAKELAND ELECTRIC C.D. MCINTOSH, JR POW	6	6,994	3,842		EVER
1070005	GEORGIA-PACIFIC CORP. PULP/PAPER MILL	15	3,703	4,329		OKEF,WOLF
1070025	SEMINOLE ELECTRIC COOPERATIVE, INC.	1	10,912	6,779		CHAS,OKEF,SAMA,WOLF
		2	12,775	6,508		CHAS,OKEF,SAMA,WOLF
1130005	EXXONMOBIL PRODUCTION COMPANY	34	1,789	1,705		BRET
1130014	PETRO OPERATING COMPANY	10	417	453		BRET
1210003	PROGRESS ENERGY FLORIDA, INC. FL POWER S	1	657	0		SAMA
		2	809	0		SAMA
		3	740	0		SAMA
1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	11	385	450		SAMA
		2	449	524		SAMA
		4	736	860		SAMA
		6	554	647		SAMA
		7	621	726		SAMA

June 1, 2007
rev

Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Air Quality Policy Division
Geographic Strategies Group
Research Triangle Park, NC

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Abbreviations and Acronyms

BACT - Best Available Control Technology

BART - Best Available Retrofit Technology

CAA - Clean Air Act

CAIR - Clean Air Interstate Rule

CFR - Code of Federal Regulations

dv - Deciviews

EPA - Environmental Protection Agency

FLM - Federal Land Manager

FR - Federal Register

NOx - A mixture of nitrogen dioxide (NO_2), nitric oxide (NO), and other nitrogen oxide gases

NAAQS - National Ambient Air Quality Standard

OAQPS - Office of Air Quality Planning and Standards

$PM_{2.5}$ - Particulate Matter of 2.5 microns or less in size

RHR - Regional Haze Rule

RPG - Reasonable Progress Goal

RPO - Regional Planning Organization

SIP - State Implementation Plan

yr - Year

1.0 INTRODUCTION

The purpose of this document is to provide guidance to States in setting reasonable progress goals (RPGs) as part of their regional haze state implementation plans (SIPs) and in deciding those measures necessary to meet these goals. We emphasize that this document is merely guidance and that States or the Environmental Protection Agency (EPA) may elect to follow or deviate from this guidance, as appropriate. The ultimate determination of whether a given SIP submission by a State meets the statutory requirements of sections 169A and 169B of the Clean Air Act (CAA) and the regional haze regulations at 40 CFR 51.300 - 309 will be accomplished through notice and comment rulemaking in which the facts and circumstances of each State submission will be evaluated by EPA.

Under the Tribal Authority Rule, 40 CFR part 49, Tribes have the authority to seek "treatment as a State" for purposes of administering certain CAA programs, including the regional haze program. Whether Tribes seek this authority or not, EPA encourages Tribes to participate in the regional planning efforts to address visibility and to consult with neighboring States as they develop their regional haze SIPs. We hope that this guidance will provide Tribes with an understanding of the process for establishing RPGs that will assist them in the consultation process.

1.1 Legislative and Regulatory History

The CAA was amended in August 1977, and a new section 169A was added for the protection of visibility in mandatory class I Federal areas (Class I areas) of great scenic importance. In section 169A(a)(1), Congress established the national goal for visibility protection:

> *Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution.*

Section 169A(a)(4), in part, requires EPA to "promulgate regulations to assure reasonable progress toward meeting the national goal." The CAA also requires States to submit SIPs containing such emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward meeting the goal.[1]

[1] CAA §169A(b)(2).

In the CAA Amendments of 1990, Congress added section 169B to strengthen and reaffirm the national goal. Section169B(e) calls for EPA to "carry out the Administrator's regulatory responsibilities under [section 169A], including criteria for measuring 'reasonable progress' toward the national goal."

In response to these mandates, EPA promulgated the regional haze rule (RHR) on July 1, 1999.[2] Under section 51.308(d)(1) of this rule, States must "establish goals (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility conditions" for each Class I area within a State. These RPGs must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period.[3]

The RHR also requires States to submit a long-term strategy that includes such measures as are necessary to achieve the RPG for each Class I area.[4] The regulations require States to consider major and minor stationary sources, mobile sources, and area sources in developing their long-term strategies. In addition, States must submit a SIP that contains either emission limitations representing best available retrofit technology (BART) for certain sources put into operation between 1962 and 1977 *or* alternative measures that provide for greater reasonable progress than BART.[5] The BART requirements were addressed in a rule revising certain provisions of the regulations in section 51.308(e) and promulgating the BART Guidelines.[6]

1.2 Meaning of the Term "Reasonable Progress Goal"

States must establish RPGs, measured in deciviews (dv), for each Class I area for the purpose of improving visibility on the haziest days and ensuring no degradation in visibility on the clearest days over the period of each implementation plan.[7] RPGs are interim goals that represent incremental visibility improvement over time toward the goal of natural background conditions and are developed in consultation with other affected States and Federal Land

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[2] 64 FR 35714 (codified at 40 CFR 51.300-309).

[3] 40 CFR 51.308(d)(1).

[4] 40 CFR 51.308(d)(3).

[5] 40 CFR 51.308(e).

[6] 70 FR 39104 (July 6, 2005).

[7] 40 CFR 51.308(d)(1).

Managers (FLM).[8]

In determining what would constitute reasonable progress, section 169A(g) of the CAA requires States to consider the following four factors:

- The costs of compliance;
- The time necessary for compliance;
- The energy and non-air quality environmental impacts of compliance; and
- The remaining useful life of existing sources that contribute to visibility impairment.[9]

States must demonstrate in their SIPs how these factors are taken into consideration in selecting the RPG for each Class I area in the State.

The discussion of the statutory factors in this guidance is largely aimed at helping States apply these factors in considering measures for point sources. States may find that the factors can be applied to sources other than point sources; the meaning of the factors, however, should not be unduly strained in order to fit non-point sources. In other words, if common sense dictates that a particular statutory factor cannot be applied to a particular source category, then the State's analysis may reflect that fact, and emissions reductions from such sources may still be included in the SIP.

As noted above, the RHR establishes an additional analytical requirement for States in the process of establishing the RPG. This analytical requirement requires States to determine the rate of improvement in visibility needed to reach natural conditions by 2064, and to set each RPG taking this "glidepath" into account.[10] (The process for determining the glidepath is discussed later in this document.) EPA adopted this approach, in part, to ensure that States use a common analytical framework that accounts for the regional differences affecting visibility and, in part, to ensure an informed and equitable decision making process. The glidepath is not a presumptive target, and States may establish a RPG that provides for greater, lesser, or equivalent visibility improvement as that described by the glidepath.

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[8] 40 CFR 51.308(d)(1)(iv) and 51.308(i).

[9] CAA §169A(g)(1); 40 CFR 51.308(d)(1)(i)(A).

[10] 40 CFR 51.308(d)(1)(i)(B).

In deciding what amount of emissions reduction is appropriate in setting the RPG, you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal.

1.3 Relationship of Reasonable Progress to BART and the Long-Term Strategy

The RPGs, the long-term strategy, and BART (or alternative measures in lieu of BART) are the three main elements of the regional haze SIPs that States are required to submit by December 17, 2007. The long-term strategy and BART emissions limitations or other alternative measures, including cap-and-trade programs or other economic incentive approaches, are inherently related to the RPG. The long-term strategy is the compilation of "enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the [RPGs],"[11] and is the means through which the State ensures that its RPG will be met. BART emissions limits (or alternative measures in lieu of BART, such as the Clean Air Interstate Rule (CAIR)) are one set of measures that must be included in the SIP to ensure that an area makes reasonable progress toward the national goal, and the visibility improvement resulting from BART (or a BART alternative) is included in the development of the RPG.

[11] 40 CFR 51.308(d)(3).

2.0 Overview Of the Process for Developing the RPG

Development of the RPG for each Class I area should be a collaborative process among State, local, and Tribal authorities, Regional Planning Organizations (RPOs), and FLMs. Steps for developing RPGs will be briefly outlined in this section of the guidance, along with references to other guidance and rules where additional detail can be found. The remaining sections of this guidance expand on particular aspects of these steps. In addition, as this is guidance for States in developing RPGs, the use of "you" through the rest of the document refers to States.

2.1 Establish Baseline and Natural Visibility Conditions

To track progress toward the national goal, the RHR, among other things, requires you to establish the "baseline conditions" representing visibility for the best and worst days at the time the regional haze program is established for each Class I area. Once established, the baseline represents the starting point from which reasonable progress will be measured. The RHR also requires you to estimate "natural conditions" for each Class I area that represents the visiblity conditions that would exist in the absence of man-made impairment.

As explained in the RHR, the baseline for each Class I area is the average visibility (in dv) for the 20 percent most impaired days, or "worst days", and for the 20 percent least impaired days, or "best days," for the years 2000 through 2004.[12] Using available monitoring data for the 2000 to 2004 time period, you are required to calculate the baseline by averaging the annual values (in dv) for the 20 percent worst days in each year (yr) to produce a single value (in dv) that represents the baseline conditions for the worst days. You should follow the same approach for determining the value that represents the baseline conditions for the best days. Natural conditions at each Class I area are also expressed by reference to the level of visibility (in dv) for the 20 percent most impaired and least impaired days.[13]

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[12] 64 FR at 35730.

[13] For more detail on determining baseline and natural conditions, you can review the preamble and regulations in the RHR, 64 FR at 35728 – 35730, 40 CFR 51.308(d)(2), EPA's *Guidance for Tracking Progress Under the Regional Haze Rule*, EPA-454/B-03-004 (September 2003) available at www.epa.gov/ttn/oarpg/t1/memoranda/rh_tpurhr_gd.pdf, and EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, EPA-454/B-03-005 (September 2003) available at www.epa.gov/ttn/oarpg/t1/memoranda/rh_envcurhr_gd.pdf.

2.2 Determine the Glidepath, or Uniform Rate of Progress

By comparing baseline conditions with natural conditions, you can determine the uniform rate of visibility improvement, or progress, needed to reach natural conditions by 2064 for each Class I area. Figure 1, below, illustrates the basic steps in the process for calculating the uniform rate of progress toward natural conditions for the first planning period at a hypothetical Class I area.

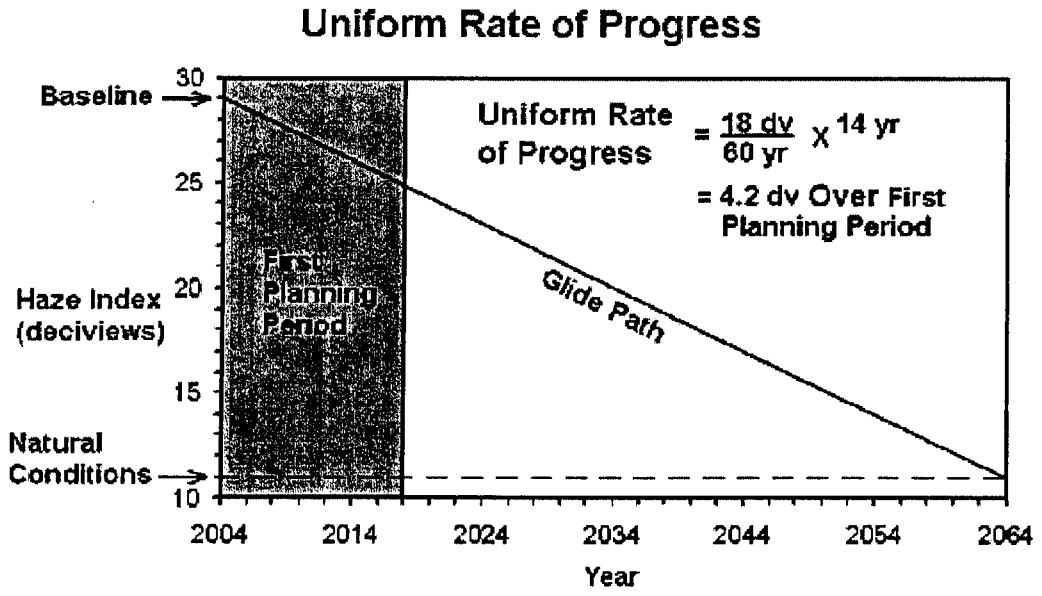


Figure 1

Figure 1 Example of a Uniform Rate of Progress

- Compare baseline conditions to natural conditions. The difference between these two represents the amount of progress needed to reach natural visibility conditions. In this example, the State has determined that the baseline for the 20 percent worst days for the Class I area is 29 dv and estimated that natural background is 11 dv, a difference of 18 dv.

- Calculate the annual average visibility improvement needed to reach natural conditions by 2064 by dividing the total amount of improvement needed by 60 years (the period between 2004 and 2064). In this example, this value is 0.3 dv/yr.

- Multiply the annual average visibility improvement needed by the number of years in the first planning period (the period from 2004 until 2018). In this example, this value is 4.2 dv. This is the uniform rate of progress that would be needed during the first planning period to attain natural visibility conditions by 2064.

If you were to achieve this steady improvement in visibility over the next 60 years, you would reach the national goal by 2064.

2.3 Identify and Analyze the Measures Aimed at Achieving the Uniform Rate of Progress.

The next step in setting an RPG is to identify and analyze the measures aimed at achieving the uniform rate of progress and to determine whether these measures are reasonable based on the statutory factors identified in Section 1.2 above. To meet this requirement, we suggest the following approach which ensures that States consider all reasonable measures in developing their regional haze SIPs:

- Identify the key pollutants and sources and/or source categories that are contributing to visibility impairment at each Class I area. The sources of impairment for the most impaired and least impaired days may differ. Section 3 discusses this process.

- Identify the control measures and associated emission reductions that are expected to result from compliance with existing rules *and* other available measures for the sources and source categories that contribute significantly to visibility impairment. This is covered in more detail in Section 4.

- Determine what additional control measures would be reasonable based on the statutory factors and other relevant factors for the sources and/or source categories you have identified.

- Estimate through the use of air quality models the improvement in visibility that would result from implementation of the control measures you have found to be reasonable and compare this to the uniform rate of progress.

Another possible approach that some States and RPOs are using is to "back out" the measures necessary to achieve the uniform rate of progress. In this process, States are using dispersion modeling to estimate the visibility impacts of a specific percentage reduction in visibility impairing pollutants. The resulting visibility conditions are then compared to the uniform rate of progress. Using this process, States will be able to identify a percentage

reduction in visibility impairing pollutants that would provide progress at or beyond the uniform rate of progress. In a separate step, States would consider the statutory factors along with other relevant factors to select appropriate measures to achieve the identified reduction in emissions. States can thus identify the measures that would be needed to achieve the uniform rate of progress at a Class I area and determine whether such measures are reasonable.

2.4 Establish a RPG

In developing a RPG, you must consult with other States with emissions sources that may reasonably be anticipated to cause or contribute to visibility impairment at Class I areas in your State.[14] The regulations anticipate that States may not always agree on what measures would be reasonable or on the appropriateness of a RPG. We encourage States to work together early and often to resolve such issues. In addition, the FLMs may provide insight and assistance to States in identifying regional approaches to address the RPG.

The improvement in visibility resulting from implementation of the measures you have found to be reasonable, considering the uniform rate of progress, is the amount of progress that represents your RPG. The regional haze rule requires you to clearly support your RPG determination in your SIP submission based on the statutory factors.[15]

[14] 40 CFR 51.308(d)(1)(iv).

[15] 40 CFR 51.308(d)(1)(i)(A).

3.0 Identifying Key Pollutants and Source Categories for the First Planning Period

This process begins with the identification of key pollutants and source categories that contribute to visibility impairment at the Class I area. Such analysis has been the subject of considerable study over the past decade, including studies by the Grand Canyon Visibility Transport Commission and ongoing work by RPOs. For the purpose of this document, it is assumed that analyses identifying the key pollutants contributing to visibility impairment have been conducted for each Class I area.

3.1 Identification of Source Categories From Which These Pollutants and Their Precursors Are Emitted

Once the key pollutants contributing to visibility impairment at each Class I area have been identified, the sources or source categories responsible for emitting these pollutants or pollutant precursors can also be determined. There are several tools and techniques being employed by the RPOs to do so, including analysis of emission inventories, source apportionment, trajectory analysis, and atmospheric modeling. Technical guidance on these tools and techniques is beyond the scope of this document. Instead, this document focuses on policy considerations relevant to the identification of which source categories should be considered as part of the regional haze SIP development process.

When identifying the sources or source categories responsible for regional haze, you should consider the relationship between the RPG and the requirements for long-term strategies. The regulations require States to consider major and minor stationary sources, as well as mobile and area sources, in developing long-term strategies.[16] At a minimum, the regulations require you to consider several factors when developing a long-term strategy, including the following:

- Emissions reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment and those taken to attain the fine particulate matter ($PM_{2.5}$) national ambient air quality standards (NAAQS).
- Measures to mitigate the impact of construction activities.
- Smoke management techniques for agricultural and forestry management purposes.

[16] 40 CFR 51.308(d)(3)(iv).

- Anticipated visibility effects from changes in point, area, and mobile source emissions.[17]

As illustrated by these factors, States should consider a broad array of sources and activities when deciding which sources or source categories contribute significantly to visibility impairment.

[17] 40 CFR 51.308(d)(3)(v).

4.0 Identify Control Measures for Contributing Source Categories for the First Planning Period

There are numerous possible conceptual approaches that you can use to identify control measures for the long-term strategy and the related RPG. We suggest beginning by concentrating on possible emissions reductions of several pollutant species from a few selected source sectors, focusing on those source categories that may have the greatest impact on visibility at Class I areas, considering cost and the other factors discussed further in Section 5.0.

4.1 Consideration of Emissions Reductions from State, Federal, and Local Control Measures

One important factor to keep in mind when establishing a RPG is that you cannot adopt a RPG that represents less visibility improvement than is expected to result from the implementation of other CAA requirements.[18] You must therefore determine the amount of emission reductions that can be expected from identified sources or source categories as a result of requirements at the local, State, and federal levels during the planning period of the SIP and the resulting improvements in visibility at Class I areas. Given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and it may be all that is necessary to achieve reasonable progress in the first planning period for some States.

The first step in this process is to identify the baseline emissions inventory year on which your strategies are based. For the first RHR SIP, we anticipate that States will use 2002 as the baseline year for emission inventories.[19] If you do use 2002, you may take credit in your long-term strategy for emission reductions achieved after 2002. This includes emission reductions from measures implemented to attain the ozone and $PM_{2.5}$ NAAQS,[20] and Federal programs, such as the national mobile source program and federal standards for hazardous air pollutants (air toxics).

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[18] 40 CFR 51.308(d)(1)(vi).

[19] 40 CFR 51.308(d)(3)(iii) provides that the baseline emission inventory year is presumed to be the most recent year of the consolidated emissions inventory for the SIP. A memorandum from OAQPS, entitled *2002 Base Year Emission Inventory SIP Planning: 8-hr Ozone, PM 2.5, and Regional Haze Programs* (November 18, 2002) ("2002 EI Memo"), identifies 2002 as the anticipated baseline emission inventory year for regional haze. See www.epa.gov/ttn/oarpg/t1/memoranda/2002bye_gm.pdf

[20] 2002 EI Memo at 3-4.

4.2 Identification of Additional Emissions Control Strategies for the Source Categories Identified

After determining the amount of emissions reductions of visibility impairing pollutants that may be expected from implementation of other CAA programs, you will be ready to identify any additional measures that are reasonable. The RHR gives States wide latitude to determine additional control requirements, and there are many ways to approach identifying additional reasonable measures; however, you must at a minimum, consider the four statutory factors. Based on the contribution from certain source categories and the magnitude of their emissions you may determine that little additional analysis is required to determine further controls are not warranted for that category. As discussed further in section 5, you have considerable flexibility in how you take these factors into consideration. In addition to source-specific controls, emissions cap-and-trade programs may be considered. Sources of information on control techniques for specific source categories include the RACT/BACT/LAER Clearinghouse and EPA's AIRControlNet database.[21]

One approach that you could take to streamline what could be an extremely complex task would be to first identify alternative control scenarios with different levels of stringency. Each control scenario would assume application of specific control levels or measures to the sources or source categories you have identified as the significant sources of visibility impairment. As indicated previously in section 4.1, the starting point for this assessment is the visibility improvement achieved as a result of BART, the CAIR, and the implementation of other CAA programs, including other measures for attainment of the ozone and $PM_{2.5}$ NAAQS. You would then consider whether any additional control scenarios are reasonable based on your consideration of the statutory factors and any other factors you have determined are relevant.

Another approach you could take, consistent with the "back out" approach discussed in section 2.3, would involve identifying the set of emissions control measures that achieves the target percentage reductions in visibility-impairing pollutants associated with progress at or beyond the uniform rate of progress. The selection of control measures to include in this set would be guided by your consideration of the statutory factors and any other factors you have determined are relevant.

Note that for some sources determined to be subject to BART, the State will already have completed a BART analysis. Since the BART analysis is based, in part, on an assessment of many of the same factors that must be addressed in establishing the RPG, it is reasonable to

[21] Information on AirControlNET can be found at www.epa.gov/ttn/ecas/econtrol.html. The RACT/BACT/LAER Clearinghouse is located at http://cfpub.epa.gov/rblc/htm/bl02.cfm.

conclude that any control requirements imposed in the BART determination also satisfy the RPG-related requirements for source review in the first RPG planning period. Hence, you may conclude that no additional emissions controls are necessary for these sources in the first planning period.

5.0 Applying Statutory Factors to Potentially Affected Stationary Sources

In determining reasonable progress, CAA §169A(g)(1) requires States to take into consideration a number of factors. However, you have flexibility in how to take into consideration these statutory factors and any other factors that you have determined to be relevant. For example, the factors could be used to select which sources or activities should or should not be regulated, or they could be used to determine the level or stringency of control, if any, for selected sources or activities, or some combination of both. The factors may be considered both individually and/or in combination. As noted in section 4.1, given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, these reductions may be all that is necessary to achieve reasonable progress in the first planning period for some States. Also, as noted in section 4.2, it is not necessary for you to reassess the reasonable progress factors for sources subject to BART for which you have already completed a BART analysis.

5.1 Reasonable Progress Statutory Factor (a): Costs of Compliance

The first factor to take into consideration is the "costs of compliance." In this context we believe that the cost of compliance factor can be interpreted to encompass the cost of compliance for individual sources or source categories, and more broadly the implication of compliance costs to the health and vitality of industries within a state. For additional guidance on applying the cost of compliance factor to stationary sources, you may wish to consult the BART guidelines, referenced above.

To assess compliance costs for individual sources or source categories potentially subject to emission limitations, we suggest that you use established control cost analysis techniques. For stationary sources, generally this involves the following:[22]

a) Identify the emissions units to be controlled;

b) Identify the design parameters for emissions controls; and

c) Develop cost estimates based upon those design parameters.

[22] As noted above, application of the cost factor to non-point sources is beyond the scope of this guidance. This is also true for mobile sources.

You should evaluate both average and incremental costs. To maintain and improve consistency wherever possible, cost estimates should be based on EPA's *Air Pollution Control Cost Manual*.[23]

In considering the cost of compliance factor, you should keep in mind that different pollutants differently impact visibility impairment. For example, on a ton basis, sulfur dioxide-related particles have a greater impact on visibility impairment than crustal material. Therefore, in assessing additional emissions reduction strategies for source categories or individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation, especially if the strategies reduce different groups of pollutants.

5.2 Reasonable Progress Statutory Factor (b): Time Necessary for Compliance

The second factor is the "time necessary for compliance." It may be appropriate for you to use this factor to adjust the RPG to reflect the degree of improvement in visibility achievable within the period of the first SIP if the time needed for full implementation of a control measure (or measures) will extend beyond 2018. For example, if you anticipate that constraints on the availability of construction labor will preclude the installation of controls at all sources of a particular category by 2018, the visibility improvement anticipated from installation of controls at the percentage of sources that *could* be controlled within the strategy period should be considered in setting the RPG and in establishing the SIP requirements to meet the RPG.

5.3 Reasonable Progress Statutory Factor (c): Energy and Non-Air Impacts

The third factor is "energy and non-air environmental impacts." In assessing energy impacts, you may want to consider whether the energy requirements associated with a control technology result in energy penalties. For example, controls on diesel engines may decrease the engine's fuel efficiency, leading to an increase in diesel fuel consumption. Or, a particular control may require a fuel unavailable in the area. To the extent that these considerations are quantifiable they should be included in the engineering analyses supporting compliance cost estimates.

Some examples of non-air environmental impacts that you may wish to consider, are the effects of the waste stream that may be generated by a particular control technology, and/or other

[23] Any additional information used for the cost calculations, including any information supplied by vendors that affects your assumptions regarding purchased equipment costs, equipment life, replacement of major components, and any other element of the calculation that differs from the *Control Cost Manual*, should be documented. EPA's *Control Cost Manual* is located at: www.epa.gov/ttncatc1/products.html#ccecinfo.

resource consumption rates such as water, water supply, and waste water disposal. To the extent that these considerations are quantifiable, they should also be included in the analyses supporting compliance cost estimates.

For additional guidance on applying this factor to stationary sources, you may wish to consult the BART Guidelines, referenced above.

5.4 Reasonable Progress Statutory Factor (d): The Remaining Useful Life of the Source

The fourth statutory factor is "the remaining useful life of any existing source subject to [reasonable progress] requirements." This factor is generally best treated as one element of the overall cost analysis. The "remaining useful life" of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's *Air Pollution Control Cost Manual* require the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life of the source will clearly exceed this time period, the remaining useful life factor has essentially no effect on control costs and on the reasonable progress determination process. Where the remaining useful life of the source is less than the time period for amortizing the costs of the retrofit control, you may wish to use this shorter time period in your cost calculations.

For additional guidance on applying this factor to stationary sources, you may wish to consult the BART Guidelines, referenced above.

accordance with the regulations of the Department of Transportation,[3] or

(e) Containers that are accessible only to individuals authorized to handle or use them, or to work in the vicinity of the containers, if the contents are identified to these individuals by a readily available written record (examples of containers of this type are containers in locations such as water-filled canals, storage vaults, or hot cells). The record must be retained as long as the containers are in use for the purpose indicated on the record; or

(f) Installed manufacturing or process equipment, such as reactor components, piping, and tanks.

[56 FR 23401, May 21, 1991, as amended at 60 FR 20185, Apr. 25, 1995]

§ 20.1906 Procedures for receiving and opening packages.

(a) Each licensee who expects to receive a package containing quantities of radioactive material in excess of a Type A quantity, as defined in §71.4 and appendix A to part 71 of this chapter, shall make arrangements to receive—

(1) The package when the carrier offers it for delivery; or

(2) Notification of the arrival of the package at the carrier's terminal and to take possession of the package expeditiously.

(b) Each licensee shall—

(1) Monitor the external surfaces of a labeled[3a] package for radioactive contamination unless the package contains only radioactive material in the form of a gas or in special form as defined in 10 CFR 71.4;

(2) Monitor the external surfaces of a labeled[3a] package for radiation levels unless the package contains quantities of radioactive material that are less than or equal to the Type A quantity, as defined in §71.4 and appendix A to part 71 of this chapter; and

(3) Monitor all packages known to contain radioactive material for radioactive contamination and radiation levels if there is evidence of degradation of package integrity, such as packages that are crushed, wet, or damaged.

(c) The licensee shall perform the monitoring required by paragraph (b) of this section as soon as practical after receipt of the package, but not later than 3 hours after the package is received at the licensee's facility if it is received during the licensee's normal working hours, or not later than 3 hours from the beginning of the next working day if it is received after working hours.

(d) The licensee shall immediately notify the final delivery carrier and the NRC Operations Center (301–816–5100), by telephone, when—

(1) Removable radioactive surface contamination exceeds the limits of §71.87(i) of this chapter; or

(2) External radiation levels exceed the limits of §71.47 of this chapter.

(e) Each licensee shall—

(1) Establish, maintain, and retain written procedures for safely opening packages in which radioactive material is received; and

(2) Ensure that the procedures are followed and that due consideration is given to special instructions for the type of package being opened.

(f) Licensees transferring special form sources in licensee-owned or licensee-operated vehicles to and from a work site are exempt from the contamination monitoring requirements of paragraph (b) of this section, but are not exempt from the survey requirement in paragraph (b) of this section for measuring radiation levels that is required to ensure that the source is still properly lodged in its shield.

[56 FR 23401, May 21, 1991, as amended at 57 FR 39357, Aug. 31, 1992; 60 FR 20185, Apr. 25, 1995; 63 FR 39482, July 23, 1998]

Subpart K—Waste Disposal

SOURCE: 56 FR 23403, May 21, 1991, unless otherwise noted.

[3] Labeling of packages containing radioactive materials is required by the Department of Transportation (DOT) if the amount and type of radioactive material exceeds the limits for an excepted quantity or article as defined and limited by DOT regulations 49 CFR 173.403 (m) and (w) and 173.421–424.

[3a] Labeled with a Radioactive White I, Yellow II, or Yellow III label as specified in U.S. Department of Transportation regulations, 49 CFR 172.403 and 172.436–440.

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§ 20.2001 General requirements.

(a) A licensee shall dispose of licensed material only—

(1) By transfer to an authorized recipient as provided in § 20.2006 or in the regulations in parts 30, 40, 60, 61, 63, 70, and 72 of this chapter;

(2) By decay in storage; or

(3) By release in effluents within the limits in § 20.1301; or

(4) As authorized under §§ 20.2002, 20.2003, 20.2004, or § 20.2005.

(b) A person must be specifically licensed to receive waste containing licensed material from other persons for:

(1) Treatment prior to disposal; or

(2) Treatment or disposal by incineration; or

(3) Decay in storage; or

(4) Disposal at a land disposal facility licensed under part 61 of this chapter; or

(5) Disposal at a geologic repository under part 60 or part 63 of this chapter.

[56 FR 23403, May 21, 1991, as amended at 66 FR 55789, Nov. 2, 2001]

§ 20.2002 Method for obtaining approval of proposed disposal procedures.

A licensee or applicant for a license may apply to the Commission for approval of proposed procedures, not otherwise authorized in the regulations in this chapter, to dispose of licensed material generated in the licensee's activities. Each application shall include:

(a) A description of the waste containing licensed material to be disposed of, including the physical and chemical properties important to risk evaluation, and the proposed manner and conditions of waste disposal; and

(b) An analysis and evaluation of pertinent information on the nature of the environment; and

(c) The nature and location of other potentially affected licensed and unlicensed facilities; and

(d) Analyses and procedures to ensure that doses are maintained ALARA and within the dose limits in this part.

§ 20.2003 Disposal by release into sanitary sewerage.

(a) A licensee may discharge licensed material into sanitary sewerage if each of the following conditions is satisfied:

(1) The material is readily soluble (or is readily dispersible biological material) in water; and

(2) The quantity of licensed or other radioactive material that the licensee releases into the sewer in 1 month divided by the average monthly volume of water released into the sewer by the licensee does not exceed the concentration listed in table 3 of appendix B to part 20; and

(3) If more than one radionuclide is released, the following conditions must also be satisfied:

(i) The licensee shall determine the fraction of the limit in table 3 of appendix B to part 20 represented by discharges into sanitary sewerage by dividing the actual monthly average concentration of each radionuclide released by the licensee into the sewer by the concentration of that radionuclide listed in table 3 of appendix B to part 20; and

(ii) The sum of the fractions for each radionuclide required by paragraph (a)(3)(i) of this section does not exceed unity; and

(4) The total quantity of licensed and other radioactive material that the licensee releases into the sanitary sewerage system in a year does not exceed 5 curies (185 GBq) of hydrogen-3, 1 curie (37 GBq) of carbon-14, and 1 curie (37 GBq) of all other radioactive materials combined.

(b) Excreta from individuals undergoing medical diagnosis or therapy with radioactive material are not subject to the limitations contained in paragraph (a) of this section.

[56 FR 23403, May 21, 1991, as amended at 60 FR 20185, Apr. 25, 1995]

§ 20.2004 Treatment or disposal by incineration.

(a) A licensee may treat or dispose of licensed material by incineration only:

(1) As authorized by paragraph (b) of this section; or

(2) If the material is in a form and concentration specified in § 20.2005; or

(3) As specifically approved by the Commission pursuant to § 20.2002.

(b)(1) Waste oils (petroleum derived or synthetic oils used principally as lubricants, coolants, hydraulic or insulating fluids, or metalworking oils)

that have been radioactively contaminated in the course of the operation or maintenance of a nuclear power reactor licensed under part 50 of this chapter may be incinerated on the site where generated provided that the total radioactive effluents from the facility, including the effluents from such incineration, conform to the requirements of appendix I to part 50 of this chapter and the effluent release limits contained in applicable license conditions other than effluent limits specifically related to incineration of waste oil. The licensee shall report any changes or additions to the information supplied under §§ 50.34 and 50.34a of this chapter associated with this incineration pursuant to § 50.71 of this chapter, as appropriate. The licensee shall also follow the procedures of § 50.59 of this chapter with respect to such changes to the facility or procedures.

(2) Solid residues produced in the process of incinerating waste oils must be disposed of as provided by § 20.2001.

(3) The provisions of this section authorize onsite waste oil incineration under the terms of this section and supersede any provision in an individual plant license or technical specification that may be inconsistent.

[57 FR 57656, Dec. 7, 1992]

§ 20.2005 Disposal of specific wastes.

(a) A licensee may dispose of the following licensed material as if it were not radioactive:

(1) 0.05 microcurie (1.85 kBq), or less, of hydrogen-3 or carbon-14 per gram of medium used for liquid scintillation counting; and

(2) 0.05 microcurie (1.85 kBq), or less, of hydrogen-3 or carbon-14 per gram of animal tissue, averaged over the weight of the entire animal.

(b) A licensee may not dispose of tissue under paragraph (a)(2) of this section in a manner that would permit its use either as food for humans or as animal feed.

(c) The licensee shall maintain records in accordance with § 20.2108.

§ 20.2006 Transfer for disposal and manifests.

(a) The requirements of this section and appendix G to 10 CFR part 20 are designed to—

(1) Control transfers of low-level radioactive waste by any waste generator, waste collector, or waste processor licensee, as defined in this part, who ships low-level waste either directly, or indirectly through a waste collector or waste processor, to a licensed low-level waste land disposal facility (as defined in part 61 of this chapter);

(2) Establish a manifest tracking system; and

(3) Supplement existing requirements concerning transfers and recordkeeping for those wastes.

(b) Any licensee shipping radioactive waste intended for ultimate disposal at a licensed land disposal facility must document the information required on NRC's Uniform Low-Level Radioactive Waste Manifest and transfer this recorded manifest information to the intended consignee in accordance with appendix G to 10 CFR part 20.

(c) Each shipment manifest must include a certification by the waste generator as specified in section II of appendix G to 10 CFR part 20.

(d) Each person involved in the transfer for disposal and disposal of waste, including the waste generator, waste collector, waste processor, and disposal facility operator, shall comply with the requirements specified in section III of appendix G to 10 CFR part 20.

[63 FR 50128, Sept. 21, 1998]

§ 20.2007 Compliance with environmental and health protection regulations.

Nothing in this subpart relieves the licensee from complying with other applicable Federal, State, and local regulations governing any other toxic or hazardous properties of materials that may be disposed of under this subpart.

Subpart L—Records

SOURCE: 56 FR 23404, May 21, 1991, unless otherwise noted.

§ 20.2101 General provisions.

(a) Each licensee shall use the units: curie, rad, rem, including multiples and subdivisions, and shall clearly indicate the units of all quantities on records required by this part.

CHAPTER 46.

ATLANTIC INTERSTATE LOW-LEVEL RADIOACTIVE WASTE COMPACT IMPLEMENTATION ACT

SECTION 48-46-10. Citation of chapter.

This chapter may be cited as the "Atlantic Interstate Low-Level Radioactive Waste Compact Implementation Act".

SECTION 48-46-20. Purpose.

The purpose of this act is to establish South Carolina as a member of the Atlantic Low-Level Radioactive Waste Compact, known in federal statute as the "Northeast Interstate Low-Level Radioactive Waste Management Compact" and to authorize and direct specific processes and procedures that are necessary to implement South Carolina's responsibilities in the compact.

SECTION 48-46-30. Definitions.

As used in this chapter, unless the context clearly requires a different construction:
(1) "Allowable costs" means costs to a disposal site operator of operating a regional disposal facility. These costs are limited to costs determined by standard accounting practices and regulatory findings to be associated with facility operations.
(2) "Atlantic Compact" means the Northeast Interstate Low-Level Radioactive Waste Management Compact as defined in the "Omnibus Low-Level Radioactive Waste Compact Consent Act of 1985", Public Law 99-240, Title II. Use of the term "Atlantic Compact" does not change in any way the substance of and is to be considered identical to the Northeast Interstate Low-Level Radioactive Waste Management Compact.
(3) "Atlantic Compact Commission" or "compact commission" means the governing body of the Atlantic Compact, consisting of voting members appointed by the governors of Connecticut, New Jersey, and South Carolina.
(4) "Board" means the South Carolina Budget and Control Board or its designated official.
(5) "Decommissioning trust fund" means the trust fund established pursuant to a Trust Agreement dated March 4, 1981, among Chem-Nuclear Systems, Inc. (grantor), the South Carolina Budget and Control Board (beneficiary), and the South Carolina State Treasurer (trustee), whose purpose is to assure adequate funding for decommissioning of the disposal site, or any successor fund with a similar purpose.
(6) "Disposal rates" means the price paid by customers of a regional disposal facility for disposal of waste, including any price schedule or breakdown of the price into discrete elements or cost components.
(7) "Extended care maintenance fund" means the "escrow fund for perpetual care" that is used for custodial, surveillance, and maintenance costs during the period of institutional control and any post-closure observation period specified by the Department of Health and Environmental Control and for activities associated with closure of the site as provided for in Section 13-7-30(4).
(8) "Facility operator" means a public or private organization, corporation, or agency that operates a regional disposal facility in South Carolina.
(9) "Generator" means a person, organization, institution, private corporation, and government agency that produces Class A, B, or C radioactive waste.
(10) "Maintenance" means active maintenance activities as specified by the Department of Health and Environmental Control, including pumping and treatment of groundwater and the repair and replacement of disposal unit covers.

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(11) "Nonregional generator" means a waste generator who produces waste within a state that is not a member of the Atlantic Compact, whether or not this waste is sent to facilities located within the Atlantic Compact region for purposes of consolidation, treatment, or processing for disposal.
(12) "Nonregional waste" means waste produced by a nonregional generator.
(13) "Person" means an individual, corporation, business enterprise, or other legal entity, either public or private, and expressly includes states.
(14) "Price schedule" means disposal rates.
(15) "PSC" means the South Carolina Public Service Commission.
(16) "Receipts" means the total amount of money collected by the site operator for waste disposal over a given period of time.
(17) "Regional disposal facility" means a disposal facility that has been designated or accepted by the Atlantic Compact Commission as a regional disposal facility.
(18) "Regional generator" means a waste generator who produces waste within the Atlantic Compact, whether or not this waste is sent to facilities outside the Atlantic Compact region for purposes of consolidation, treatment, or processing for disposal.
(19) "Regional waste" means waste generated within a member state of the Atlantic Compact. Consistent with the regulatory position of the Department of Health and Environmental Control, Bureau of Radiological Health, dated May 1, 1986, some waste byproducts shipped for disposal that are derived from wastes generated within the Atlantic Compact region, such as residues from recycling, processing, compacting, incineration, collection, and brokering facilities located outside the Atlantic Compact region may also be considered regional waste.
(20) "Site operator" means a facility operator.
(21) "South Carolina generator" means a waste generator that produces waste within the boundaries of the State of South Carolina, whether or not this waste is sent to facilities outside South Carolina for purposes of consolidation, treatment, or processing for disposal.
(22) "Waste" means Class A, B, or C low-level radioactive waste, as defined in Title I of Public Law 99-240 and Department of Health and Environmental Control Regulation 61-63, 7.2.22, that is eligible for acceptance for disposal at a regional disposal facility.

SECTION 48-46-40. Fees for disposal of regional and nonregional radioactive waste in regional disposal facilities; disposition of fees; Higher Education Scholarship Grants.

(A)(1) The board shall approve disposal rates for low-level radioactive waste disposed at any regional disposal facility located within the State. The approval of disposal rates pursuant to this chapter is neither a regulation nor the promulgation of a regulation as those terms are specially used in Title 1, Chapter 23.
(2) The board shall adopt a maximum uniform rate schedule for regional generators containing disposal rates that include the administrative surcharges specified in Section 48-46-60(B) and surcharges for the extended custody and maintenance of the facility pursuant to Section 13-7-30(4) and that do not exceed the approximate disposal rates, excluding any access fees and including a specification of the methodology for calculating fees for large components, generally applicable to regional generators on September 7, 1999. Any disposal rates contained in a valid written agreement that were applicable to a regional generator on September 7, 1999, that differ from rates in the maximum uniform rate schedule will continue to be honored through the term of such agreement. The maximum uniform rate schedule approved under this section becomes effective immediately upon South Carolina' s membership in the Atlantic Compact. The maximum uniform rate schedule shall be the rate schedule applicable to regional waste whenever it is not superseded by an adjusted rate approved by the board pursuant to paragraph (3) of this subsection or by special disposal rates approved pursuant to paragraphs (5) or (6)(e) of this subsection.
(3) The board may at any time of its own initiative, at the request of a site operator, or at the request of the compact commission, adjust the disposal rate or the relative proportions of the individual components that constitute the overall rate schedule. Except as adjusted for inflation in subsection (4), rates adjusted in

accordance with this section, that include the administrative surcharges specified in Section 48-46-60(B) and surcharges for the extended custody and maintenance of the facility pursuant to Section 13-7-30(4), may not exceed initial disposal rates set by the board pursuant to subsection (2).

(4) In March of each year the board shall adjust the rate schedule based on the most recent changes in the most nearly applicable Producer Price Index published by the Bureau of Labor Statistics as chosen by the board or a successor index.

(5) In consultation with the site operator, the board or its designee, on a case-by-case basis, may approve special disposal rates for regional waste that differ from the disposal rate schedule for regional generators set by the board pursuant to subsections (2) and (3). Requests by the site operator for such approval shall be in writing to the board. In approving such special rates, the board or its designee, shall consider available disposal capacity, demand for disposal capacity, the characteristics of the waste, the potential for generating revenue for the State, or other relevant factors; provided, however, that the board shall not approve any special rate for an entity owned by or affiliated with the site operator. Special disposal rates approved by the board under this subsection shall be in writing and shall be kept confidential as proprietary business information for one year from the date when the bid or the request for proposal containing the special rate is accepted by the regional generator; provided, however, that such special rates when accepted by a regional generator shall be disclosed to the compact commission and to all other regional generators, which shall, to the extent permitted by applicable law, keep them confidential as proprietary business information for one year from the date when the bid or request for proposal containing this special rate is accepted by the regional generator. Within one business day of a special disposal rate's acceptance, the site operator shall notify the board, the compact commission, and the regional generators of each special rate that has been accepted by a regional generator, and the board, the compact commission, and regional generators may communicate with each other about such special rates. If any special rate approved by the board for a regional generator is lower than a disposal rate approved by the board for regional generators pursuant to subsections (2) and (3) for waste that is generally similar in characteristics and volume, the disposal rate for all regional generators shall be revised to equal the special rate for the regional generator. Regional generators may enter into contracts for waste disposal at such special rates and on comparable terms for a period of not less than six months. An officer of the site operator shall certify in writing to the board and the compact commission each month that no regional generator's disposal rate exceeds any other regional generator's special rate for waste that is generally similar in characteristics and volume, and such certification shall be subject to periodic audit by the board and the compact commission.

(6)(a) To the extent authorized by the compact commission, the board on behalf of the State of South Carolina may enter into agreements with any person in the United States or its territories or any interstate compact, state, U.S. territory, or U.S. Department of Defense military installation abroad for the importation of waste into the region for purposes of disposal at a regional disposal facility within South Carolina. No waste from outside the Atlantic Compact region may be disposed at a regional disposal facility within South Carolina, except to the extent that the board is authorized by the compact commission to enter into agreements for importation of waste.

The board shall authorize the importation of nonregional waste into the region for purposes of disposal at the regional disposal facility in South Carolina so long as nonregional waste would not result in the facility accepting more than the following total volumes of all waste:

(i) 160,000 cubic feet in fiscal year 2001;
(ii) 80,000 cubic feet in fiscal year 2002;
(iii) 70,000 cubic feet in fiscal year 2003;
(iv) 60,000 cubic feet in fiscal year 2004;
(v) 50,000 cubic feet in fiscal year 2005;
(vi) 45,000 cubic feet in fiscal year 2006;
(vii) 40,000 cubic feet in fiscal year 2007;
(viii) 35,000 cubic feet in fiscal year 2008.

After fiscal year 2008, the board shall not authorize the importation of nonregional waste for purposes of disposal.

(b) The board may approve disposal rates applicable to nonregional generators. In approving disposal rates applicable to nonregional generators, the board may consider available disposal capacity, demand for disposal capacity, the characteristics of the waste, the potential for generating revenue for the State, and other relevant factors.

(c) Absent action by the board under subsection (b) above to establish disposal rates for nonregional generators, rates applicable to these generators must be equal to those contained in the maximum uniform rate schedule approved by the board pursuant to paragraph (2) or (3) of this subsection for regional generators unless these rates are superseded by special disposal rates approved by the board pursuant to paragraph (6)(e) of this subsection.

(d) Regional generators shall not pay disposal rates that are higher than disposal rates for nonregional generators in any fiscal quarter.

(e) In consultation with the site operator, the board or its designee, on a case-by-case basis, may approve special disposal rates for nonregional waste that differ from the disposal rate schedule for nonregional generators set by the board. Requests by the site operator for such approval shall be in writing to the board. In approving such special rates, the board or its designee shall consider available disposal capacity, demand for disposal capacity, the characteristics of the waste, the potential for generating revenue for the State, and other relevant factors; provided, however, that the board shall not approve any special rate for an entity owned by or affiliated with the site operator. Special disposal rates approved by the board under this subsection shall be in writing and shall be kept confidential as proprietary business information for one year from the date when the bid or request for proposal containing the special rate is accepted by the nonregional generator; provided, however, that such special rates when accepted by a nonregional generator shall be disclosed to the compact commission and to all regional generators, which shall, to the extent permitted by applicable law, keep them confidential as proprietary business information for one year from the date when the bid or request for proposal containing the special rate is accepted by the nonregional generator. Within one business day of a special disposal rate's acceptance, the site operator shall notify the board, the compact commission, and the regional generators in writing of each special rate that has been accepted by a nonregional generator, and the board, the compact commission, and regional generators may communicate with each other about such special rates. If any special rate approved by the board for a nonregional generator is lower than a disposal rate approved by the board for regional generators for waste that is generally similar in characteristics and volume, the disposal rate for all regional generators shall be revised to equal the special rate for the nonregional generator. Regional generators may enter into contracts for waste disposal at such special rate and on comparable terms for a period of not less than six months. An officer of the site operator shall certify in writing to the board and the compact commission each month that no regional generator disposal rate exceeds any nonregional generator's special rate for waste that is generally similar in characteristics and volume, and such certification shall be subject to periodic audit by the board and the compact commission.

(B)(1) Effective upon the implementation of initial disposal rates by the board under Section 48-46-40(A), the PSC is authorized and directed to identify allowable costs for operating a regional low-level radioactive waste disposal facility in South Carolina.

(2) In identifying the allowable costs for operating a regional disposal facility, the PSC shall:

(a) prescribe a system of accounts, using generally accepted accounting principles, for disposal site operators, using as a starting point the existing system used by site operators;

(b) assess penalties against disposal site operators if the PSC determines that they have failed to comply with regulations pursuant to this section; and

(c) require periodic reports from site operators that provide information and data to the PSC and parties to these proceedings. The Office of Regulatory Staff shall obtain and audit the books and records of the site operators associated with disposal operations as determined applicable by the PSC.

(3) Allowable costs include the costs of those activities necessary for:

(a) the receipt of waste;

(b) the construction of disposal trenches, vaults, and overpacks;
(c) construction and maintenance of necessary physical facilities;
(d) the purchase or amortization of necessary equipment;
(e) purchase of supplies that are consumed in support of waste disposal activities;
(f) accounting and billing for waste disposal;
(g) creating and maintaining records related to disposed waste;
(h) the administrative costs directly associated with disposal operations including, but not limited to, salaries, wages, and employee benefits;
(i) site surveillance and maintenance required by the State of South Carolina, other than site surveillance and maintenance costs covered by the balance of funds in the decommissioning trust fund or the extended care maintenance fund;
(j) compliance with the license, lease, and regulatory requirements of all jurisdictional agencies;
(k) administrative costs associated with collecting the surcharges provided for in subsections (B) and (C) of Section 48-46-60;
(l) taxes other than income taxes;
(m) licensing and permitting fees; and
(n) any other costs directly associated with disposal operations determined by the PSC to be allowable.
Allowable costs do not include the costs of activities associated with lobbying and public relations, clean-up and remediation activities caused by errors or accidents in violation of laws, regulations, or violations of the facility operating license or permits, activities of the site operator not directly in support of waste disposal, and other costs determined by the PSC to be unallowable.
(4) Within ninety days following the end of a fiscal year, a site operator may file an application with the PSC to adjust the level of an allowable cost under subsection (3), or to allow a cost not previously designated an allowable cost. A copy of the application must be provided to the Office of Regulatory Staff. The PSC shall process such application in accordance with its procedures. If such application is approved by the PSC, the PSC shall authorize the site operator to adjust allowable costs for the current fiscal year so as to compensate the site operator for revenues lost during the previous fiscal year.
(5) A private operator of a regional disposal facility in South Carolina is authorized to charge an operating margin of twenty-nine percent. The operating margin for a given period must be determined by multiplying twenty-nine percent by the total amount of allowable costs as determined in this subsection, excluding allowable costs for taxes and licensing and permitting fees paid to governmental entities.
(6) The site operator shall prepare and file with the PSC a Least Cost Operating Plan. The plan must be filed within forty-five days of enactment of this chapter and must be revised annually. The plan shall include information concerning anticipated operations over the next ten years and shall evaluate all options for future staffing and operation of the site to ensure least cost operation, including information related to the possible interim suspension of operations in accordance with subsection (B)(7). A copy of the plan must be provided to the Office of Regulatory Staff.
(7)(a) If the board, upon the advice of the compact commission or the site operator, concludes based on information provided to the board, that the volume of waste to be disposed during a forthcoming period of time does not appear sufficient to generate receipts that will be adequate to reimburse the site operator for its costs of operating the facility and its operating margin, then the board shall direct the site operator to propose to the compact commission plans including, but not necessarily limited to, a proposal for discontinuing acceptance of waste until such time as there is sufficient waste to cover the site operator's operating costs and operating margin. Any proposal to suspend operations must detail plans of the site operator to minimize its costs during the suspension of operations. Any such proposal to suspend operations must be approved by the Department of Health and Environmental Control with respect to safety and environmental protection.
(b) Allowable costs applicable to any period of suspended operations must be approved by the PSC according to procedures similar to those provided herein for allowable operating costs. During any such suspension of operations, the site operator must be reimbursed by the board from the extended care maintenance fund for its allowable costs and its operating margin. During the suspension funding to

reimburse the board, the PSC, and the State Treasurer under Section 48-46-60(B) and funding of the compact commission under Section 48-46-60(C) must also be allocated from the extended care maintenance fund as approved by the board based on revised budgets submitted by the PSC, State Treasurer, and the compact commission.

(c) Notwithstanding any disbursements from the extended care maintenance fund in accordance with any provision of this act, the board shall continue to ensure, in accordance with Section 13-7-30, that the fund remains adequate to defray the costs for future maintenance costs or custodial and maintenance obligations of the site and other obligations imposed on the fund by this chapter.

(d) The PSC may promulgate regulations and policies necessary to execute the provisions of this section.

(8) The PSC may use any standard, formula, method, or theory of valuation reasonably calculated to arrive at the objective of identifying allowable costs associated with waste disposal. The PSC may consider standards, precedents, findings, and decisions in other jurisdictions that regulate allowable costs for radioactive waste disposal.

(9) In all proceedings held pursuant to this section, the board shall participate as a party representing the interests of the State of South Carolina, and the compact commission may participate as a party representing the interests of the compact states. The Executive Director of the Office of Regulatory Staff and the Attorney General of the State of South Carolina shall be parties to any such proceeding. Representatives from the Department of Health and Environmental Control shall participate in proceedings where necessary to determine or define the activities that a site operator must conduct in order to comply with the regulations and license conditions imposed by the department. Other parties may participate in the PSC's proceedings upon satisfaction of standing requirements and compliance with the PSC's procedures. Any site operator submitting records and information to the PSC may request that the PSC treat such records and information as confidential and not subject to disclosure in accordance with the PSC's procedures.

(10) In all respects in which the PSC has power and authority under this chapter, it shall conduct its proceedings under the South Carolina Administrative Procedures Act and the PSC's rules and regulations. The PSC is authorized to compel attendance and testimony of a site operator's directors, officers, agents, or employees.

(11) At any time the compact commission, the board, or any generator subject to payment of rates set pursuant to this chapter may file a petition against a site operator alleging that allowable costs identified pursuant to this chapter are not in conformity with the directives of this chapter or the directives of the PSC or that the site operator is otherwise not acting in conformity with the requirements of this chapter or directives of the PSC. Upon filing of the petition, the PSC shall cause a copy of the petition to be served upon the site operator. The petitioning party has the burden of proving that allowable costs or the actions of the site operator do not conform. The hearing shall conform to the rules of practice and procedure of the PSC for other cases.

(12) The PSC shall encourage alternate forms of dispute resolution including, but not limited to, mediation or arbitration to resolve disputes between a site operator and any other person regarding matters covered by this chapter.

(C) The operator of a regional disposal facility shall submit to the South Carolina Department of Revenue, the PSC, the Office of Regulatory Staff, and the board within thirty days following the end of each quarter a report detailing actual revenues received in the previous fiscal quarter and allowable costs incurred for operation of the disposal facility.

(D)(1) Within 30 days following the end of the fiscal year the operator of a regional disposal facility shall submit a payment made payable to the South Carolina Department of Revenue in an amount that is equal to the total revenues received for waste disposed in that fiscal year (with interest accrued on cash flows in accordance with instructions from the State Treasurer) minus allowable costs, operating margin, and any payments already made from such revenues pursuant to Section 48-46-60(B) and (C) for reimbursement of administrative costs to state agencies and the compact commission. The Department of Revenue shall deposit the payment with the State Treasurer.

(2) If in any fiscal year total revenues do not cover allowable costs plus the operating margin, the board must reimburse the site operator its allowable costs and operating margin from the extended care maintenance fund within thirty days after the end of the fiscal year. The board shall as soon as practicable authorize a surcharge on waste disposed in an amount that will fully compensate the fund for the reimbursement to the site operator. In the event that total revenues for a fiscal year do not cover allowable costs plus the operating margin, or quarterly reports submitted pursuant to subsection (C) indicate that such annual revenue may be insufficient, the board shall consult with the compact commission and the site operator as early as practicable on whether the provisions of Section 48-46-40(B)(7) pertaining to suspension of operations during periods of insufficient revenues should be invoked.

(E) Revenues received pursuant to item (1) of subsection (D) must be allocated as follows:

(1) The South Carolina State Treasurer shall distribute the first two million dollars received for waste disposed during a fiscal year to the County Treasurer of Barnwell County for distribution to each of the parties to and beneficiaries of the order of the United States District Court in C.A. No. 1:90-2912-6 on the same schedule of allocation as is established within that order for the distribution of "payments in lieu of taxes" paid by the United States Department of Energy.

(2) All revenues in excess of two million dollars received from waste disposed during the previous fiscal year must be deposited in a fund called the "Nuclear Waste Disposal Receipts Distribution Fund". Any South Carolina waste generator whose disposal fees contributed to the fund during the previous fiscal year may submit a request for a rebate of 33.33 percent of the funds paid by the generator during the previous fiscal year for disposal of waste at a regional disposal facility. These requests along with invoices or other supporting material must be submitted in writing to the State Treasurer within fifteen days of the end of the fiscal year. For this purpose disposal fees paid by the generator must exclude any fees paid pursuant to Section 48-46-60(C) for compact administration and fees paid pursuant to Section 48-46-60(B) for reimbursement of the PSC, the Office of Regulatory Staff, the State Treasurer, and the board for administrative expenses under this chapter. Upon validation of the request and supporting documentation by the State Treasurer, the State Treasurer shall issue a rebate of the applicable funds to qualified waste generators within sixty days of the receipt of the request. If funds in the Nuclear Waste Disposal Receipts Distribution Fund are insufficient to provide a rebate of 33.33 percent to each generator, then each generator's rebate must be reduced in proportion to the amount of funds in the account for the applicable fiscal year.

(3) All funds deposited in the Nuclear Waste Disposal Receipts Distribution Fund for waste disposed for each fiscal year, less the amount needed to provide generators rebates pursuant to item (2), shall be deposited by the State Treasurer in the "Children's Education Endowment Fund" . Thirty percent of these monies must be allocated to Higher Education Scholarship Grants and used as provided in Section 59-143-30, and seventy percent of these monies must be allocated to Public School Facility Assistance and used as provided in Chapter 144 of Title 59.

(F) Effective beginning fiscal year 2001-2002, there is appropriated annually from the general fund of the State to the Higher Education Scholarship Grants share of the Children's Education Endowment whatever amount is necessary to credit to the Higher Education Scholarship Grants share an amount not less than the amount credited to that portion of the endowment in fiscal year 1999-2000. Revenues credited to the endowment pursuant to this subsection, for purposes of Section 59-143-10, are deemed to be received by the endowment pursuant to the former provisions of Section 48-48-140(C).

SECTION 48-46-50. Appointment of commissioners, alternate commissioners and technical representatives from certain state agencies to Atlantic Compact Commission; restrictions on voting authority of commissioners.

(A) The Governor shall appoint two commissioners to the Atlantic Compact Commission and may appoint up to two alternate commissioners. These alternate commissioners may participate in meetings of the compact commission in lieu of and upon the request of a South Carolina commissioner. Technical representatives from the Department of Health and Environmental Control, the board, the PSC, and other

state agencies may participate in relevant portions of meetings of the compact commission upon the request of a commissioner, alternate commissioner, or staff of the compact commission, or as called for in the compact commission bylaws.

(B) South Carolina commissioners or alternate commissioners to the compact commission may not vote affirmatively on any motion to admit new member states to the compact unless that state volunteers to host a regional disposal facility.

(C) Compact commissioners or alternate commissioners to the Atlantic Compact Commission may not vote to approve a regional management plan or any other plan or policy that allows for acceptance at the Barnwell regional disposal facility of more than a total of 800,000 cubic feet of waste from Connecticut and New Jersey.

(D) South Carolina's commissioners or alternate commissioners to the compact commission shall cast any applicable votes on the compact commission in a manner that authorizes the importation of waste into the region for purposes of disposal at a regional disposal facility in South Carolina so long as importation would not result in the facility accepting more than the following total volumes of all waste:

(1) 160,000 cubic feet in fiscal year 2001;
(2) 80,000 cubic feet in fiscal year 2002;
(3) 70,000 cubic feet in fiscal year 2003;
(4) 60,000 cubic feet in fiscal year 2004;
(5) 50,000 cubic feet in fiscal year 2005;
(6) 45,000 cubic feet in fiscal year 2006;
(7) 40,000 cubic feet in fiscal year 2007;
(8) 35,000 cubic feet in fiscal year 2008.

South Carolina's commissioners or alternate commissioners shall not vote to approve the importation of waste into the region for purposes of disposal in any fiscal year after 2008.

SECTION 48-46-60. Governor and board authorized to take actions to join Atlantic Compact; effective date; conditions; administrative expenses; assessment of compact convention costs and expenses.

(A) The Governor and the board are authorized to take such actions as are necessary to join the Atlantic Compact including, but not limited to, petitioning the Compact Commission for membership and participating in any and all rulemaking processes. South Carolina's membership in the Atlantic Compact pursuant to this chapter is effective July 1, 2000, if by that date the Governor certifies to the General Assembly that the Compact Commission has taken each of the actions specified below. If the Compact Commission by July 1, 2000, has not taken each of the actions specified below, then South Carolina's membership shall become effective as soon thereafter as the Governor certifies that the Atlantic Compact Commission has taken these actions:

(1) adopted a binding regulation or policy in accordance with Article VII(e) of the compact establishing conditions for admission of a party state that are consistent with this act and ordered that South Carolina be declared eligible to be a party state consistent with those conditions;

(2) adopted a binding regulation or policy in accordance with Article IV(i)(11) of the Atlantic Compact authorizing a host state to enter into agreements on behalf of the compact and consistent with criteria established by the compact commission and consistent with the provisions of Section 48-46-40(A)(6)(a) and Section 48-46-50(D) with any person for the importation of waste into the region for purposes of disposal, to the extent that these agreements do not preclude the disposal facility from accepting all regional waste that can reasonably be projected to require disposal at the regional disposal facility consistent with subitem (5)(b) of this section;

(3) adopted a binding regulation or policy in accordance with Article IV(i)(12) of the Atlantic Compact authorizing each regional generator, at the generator's discretion, to ship waste to disposal facilities located outside the Atlantic Compact region;

(4) authorized South Carolina to proceed with plans to establish disposal rates for low-level radioactive waste disposal in a manner consistent with the procedures described in this chapter;

(5) adopted a binding regulation, policy, or order officially designating South Carolina as a volunteer host state for the region's disposal facility, contingent upon South Carolina's membership in the compact, in accordance with Article V.b.1. of the Atlantic Compact, thereby authorizing the following compensation and incentives to South Carolina:

(a) agreement, as evidenced in a policy, regulation, or order that the compact commission will issue a payment of twelve million dollars to the State of South Carolina. Before issuing the twelve million-dollar payment, the compact commission will deduct and retain from this amount seventy thousand dollars, which will be credited as full payment of South Carolina's membership dues in the Atlantic Compact. The remainder of the twelve million-dollar payment must be credited to an account in the State Treasurer's office, separate and distinct from the fund, styled "Barnwell Economic Development Fund". This fund, and earnings on this fund which must be credited to the fund, may only be expended for purposes of economic development in the Barnwell County area including, but not limited to, projects of the Barnwell County Economic Development Corporation and projects of the Tri-County alliance which includes Barnwell, Bamberg, and Allendale Counties and projects in the Williston area of Aiken County. Economic development includes, but is not limited to, industrial recruitment, infrastructure construction, improvement, and expansion, and public facilities construction, improvement, and expansion. These funds must be spent according to guidelines established by the Barnwell County governing body and upon approval of the board. Expenditures must be authorized by the Barnwell County governing body and with the approval of the board. Upon approval of the Barnwell County governing body and the board, the State Treasurer shall submit the approved funds to the Barnwell County Treasurer for disbursement pursuant to the authorization;

(b) adopted a binding regulation, policy, or order consistent with the regional management plan developed pursuant to Article V(a) of the Atlantic Compact, limiting Connecticut and New Jersey to the use of not more than 800,000 cubic feet of disposal capacity at the regional disposal facility located in Barnwell County, South Carolina, and also ensuring that up to 800,000 cubic feet of disposal capacity remains available for use by Connecticut and New Jersey unless this estimate of need is later revised downward by unanimous consent of the compact commission;

(c) agreement, as evidenced in a policy or regulation, that the compact commission headquarters and office will be relocated to South Carolina within six months of South Carolina's membership; and

(d) agreement, as evidenced in a policy or regulation, that the compact commission will, to the extent practicable, hold a majority of its meetings in the host state for the regional disposal facility.

(B) The board, the State Treasurer, and the PSC shall provide the required staff and may add additional permanent or temporary staff or contract for services, as well as provide for operating expenses, if necessary, to administer new responsibilities assigned under this chapter. In accordance with Article V.f.2. of the Atlantic Compact the compensation, costs, and expenses incurred incident to administering these responsibilities may be paid through a surcharge on waste disposed at regional disposal facilities within the State. To cover these costs the board shall impose a surcharge per unit of waste received at any regional disposal facility located within the State. A site operator shall collect and remit these fees to the board in accordance with the board's directions. All such surcharges shall be included within the disposal rates set by the board pursuant to Section 48-46-40.

(C) In accordance with Article V.f.3. of the Atlantic Compact, the compact commission shall advise the board at least annually, but more frequently if the compact commission deems appropriate, of the compact commission's costs and expenses. To cover these costs the board shall impose a surcharge per unit of waste received at any regional disposal facility located within the State as determined in Section 48-46-40. A site operator shall collect and remit these fees to the board in accordance with the board's directions, and the board shall remit those fees to the compact commission.

SECTION 48-46-70. Northeast Interstate Low-Level Radioactive Waste Management Compact incorporated by reference.

The Northeast Interstate Low-Level Radioactive Waste Management Compact, P.L. 99-240, Section 227, 99 Stat. 1909 (1985) as it existed on the date this act was enacted, is hereby incorporated by reference, and all terms and conditions contained therein shall have full force and effect as if set forth herein in their entirety. In addition to the express limitations on non-host state and compact commission liability provided in the Northeast Interstate Low-Level Radioactive Waste Management Compact, South Carolina will indemnify the Atlantic Compact Commission or any of the other party states for any damages incurred solely because of South Carolina's membership in the compact and for any damages associated with any injury to persons or property during the institutional control period resulting from the radioactive and waste management operations of the regional facility.

SECTION 48-46-80. Adjustment of license fees for Low-Level Radioactive Waste Shallow Land Disposal.

Pursuant to Section 48-2-10 et seq., the Department of Health and Environmental Control may adjust the radioactive materials license fee for Low-Level Radioactive Waste Shallow Land Disposal in Regulation 61-30 in an amount that will offset changes to its annual operating budget caused by projected increases or decreases in the number of permittees expected to pay fees for Radioactive Waste Transport Permits under the same regulation for shipment of low-level radioactive waste for disposal within the State.

SECTION 48-46-90. Custody and maintenance of Barnwell site following closure

(A) In accordance with Section 13-7-30, the board, or its designee, is responsible for extended custody and maintenance of the Barnwell site following closure and license transfer from the facility operator. The Department of Health and Environmental Control is responsible for continued site monitoring.
(B) Nothing in this chapter may be construed to alter or diminish the existing statutory authority of the Department of Health and Environmental Control to regulate activities involving radioactive materials and radioactive wastes.

is governed by 10 CFR part 54. Application for termination of license is to be made pursuant to § 50.82.

(b) Each license for a facility that has permanently ceased operations, continues in effect beyond the expiration date to authorize ownership and possession of the production or utilization facility, until the Commission notifies the licensee in writing that the license is terminated. During such period of continued effectiveness the licensee shall—

(1) Take actions necessary to decommission and decontaminate the facility and continue to maintain the facility, including, where applicable, the storage, control and maintenance of the spent fuel, in a safe condition, and

(2) Conduct activities in accordance with all other restrictions applicable to the facility in accordance with the NRC regulations and the provisions of the specific 10 CFR part 50 license for the facility.

[56 FR 64976, Dec. 13, 1991, as amended at 61 FR 39300, July 29, 1996]

§ 50.52 Combining licenses.

The Commission may combine in a single license the activities of an applicant which would otherwise be licensed severally.

§ 50.53 Jurisdictional limitations.

No license under this part shall be deemed to have been issued for activities which are not under or within the jurisdiction of the United States.

[21 FR 355, Jan. 19, 1956, as amended at 43 FR 6924, Feb. 17, 1978]

§ 50.54 Conditions of licenses.

Whether stated therein or not, the following shall be deemed conditions in every license issued:

(a)(1) Each nuclear power plant or fuel reprocessing plant licensee subject to the quality assurance criteria in appendix B of this part shall implement, pursuant to § 50.34(b)(6)(ii) of this part, the quality assurance program described or referenced in the Safety Analysis Report, including changes to that report.

(2) Each licensee described in paragraph (a)(1) of this section shall, by June 10, 1983, submit to the appropriate NRC Regional Office shown in appendix D of part 20 of this chapter the current description of the quality assurance program it is implementing for inclusion in the Safety Analysis Report, unless there are no changes to the description previously accepted by NRC. This submittal must identify changes made to the quality assurance program description since the description was submitted to NRC. (Should a licensee need additional time beyond June 10, 1983 to submit its current quality assurance program description to NRC, it shall notify the appropriate NRC Regional Office in writing, explain why additional time is needed, and provide a schedule for NRC approval showing when its current quality assurance program description will be submitted.)

(3) Each licensee described in paragraph (a)(1) of this section may make a change to a previously accepted quality assurance program description included or referenced in the Safety Analysis Report without prior NRC approval, provided the change does not reduce the commitments in the program description as accepted by the NRC. Changes to the quality assurance program description that do not reduce the commitments must be submitted to the NRC in accordance with the requirements of § 50.71(e). In addition to quality assurance program changes involving administrative improvements and clarifications, spelling corrections, punctuation, or editorial items, the following changes are not considered to be reductions in commitment:

(i) The use of a QA standard approved by the NRC which is more recent than the QA standard in the licensee's current QA program at the time of the change;

(ii) The use of a quality assurance alternative or exception approved by an NRC safety evaluation, provided that the bases of the NRC approval are applicable to the licensee's facility;

(iii) The use of generic organizational position titles that clearly denote the position function, supplemented as necessary by descriptive text, rather than specific titles;

(iv) The use of generic organizational charts to indicate functional relationships, authorities, and responsibilities,

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COMPANY Florida Power & Light
WITNESS R.R. LaBauve (RRL-11)
DATE 11-06-07

or, alternately, the use of descriptive text;

(v) The elimination of quality assurance program information that duplicates language in quality assurance regulatory guides and quality assurance standards to which the licensee is committed; and

(vi) Organizational revisions that ensure that persons and organizations performing quality assurance functions continue to have the requisite authority and organizational freedom, including sufficient independence from cost and schedule when opposed to safety considerations.

(4) Changes to the quality assurance program description that do reduce the commitments must be submitted to the NRC and receive NRC approval prior to implementation, as follows:

(i) Changes made to the quality assurance program description as presented in the Safety Analysis Report or in a topical report must be submitted as specified in § 50.4.

(ii) The submittal of a change to the Safety Analysis Report quality assurance program description must include all pages affected by that change and must be accompanied by a forwarding letter identifying the change, the reason for the change, and the basis for concluding that the revised program incorporating the change continues to satisfy the criteria of appendix B of this part and the Safety Analysis Report quality assurance program description commitments previously accepted by the NRC (the letter need not provide the basis for changes that correct spelling, punctuation, or editorial items).

(iii) A copy of the forwarding letter identifying the change must be maintained as a facility record for three years.

(iv) Changes to the quality assurance program description included or referenced in the Safety Analysis Report shall be regarded as accepted by the Commission upon receipt of a letter to this effect from the appropriate reviewing office of the Commission or 60 days after submittal to the Commission, whichever occurs first.

(b) No right to the special nuclear material shall be conferred by the license except as may be defined by the license.

(c) Neither the license, nor any right thereunder, nor any right to utilize or produce special nuclear material shall be transferred, assigned, or disposed of in any manner, either voluntarily or involuntarily, directly or indirectly, through transfer of control of the license to any person, unless the Commission shall, after securing full information, find that the transfer is in accordance with the provisions of the act and give its consent in writing.

(d) The license shall be subject to suspension and to the rights of recapture of the material or control of the facility reserved to the Commission under section 108 of the act in a state of war or national emergency declared by Congress.

(e) The license shall be subject to revocation, suspension, modification, or amendment for cause as provided in the act and regulations, in accordance with the procedures provided by the act and regulations.

(f) The licensee shall at any time before expiration of the license, upon request of the Commission, submit, as specified in § 50.4, written statements, signed under oath or affirmation, to enable the Commission to determine whether or not the license should be modified, suspended, or revoked. Except for information sought to verify licensee compliance with the current licensing basis for that facility, the NRC must prepare the reason or reasons for each information request prior to issuance to ensure that the burden to be imposed on respondents is justified in view of the potential safety significance of the issue to be addressed in the requested information. Each such justification provided for an evaluation performed by the NRC staff must be approved by the Executive Director for Operations or his or her designee prior to issuance of the request.

(g) The issuance or existence of the license shall not be deemed to waive, or relieve the licensee from compliance with, the antitrust laws, as specified in subsection 105a of the Act. In the event that the licensee should be found by a court of competent jurisdiction to have

violated any provision of such antitrust laws in the conduct of the licensed activity, the Commission may suspend or revoke the license or take such other action with respect to it as shall be deemed necessary.

(h) The license shall be subject to the provisions of the Act now or hereafter in effect and to all rules, regulations, and orders of the Commission. The terms and conditions of the license shall be subject to amendment, revision, or modification, by reason of amendments of the Act or by reason of rules, regulations, and orders issued in accordance with the terms of the act.

(i) Except as provided in § 55.13 of this chapter, the licensee may not permit the manipulation of the controls of any facility by anyone who is not a licensed operator or senior operator as provided in part 55 of this chapter.

(i–1) Within three months after issuance of an operating license, the licensee shall have in effect an operator requalification program which must as a minimum, meet the requirements of § 55.59(c) of this chapter. Notwithstanding the provisions of § 50.59, the licensee may not, except as specifically authorized by the Commission decrease the scope of an approved operator requalification program.

(j) Apparatus and mechanisms other than controls, the operation of which may affect the reactivity or power level of a reactor shall be manipulated only with the knowledge and consent of an operator or senior operator licensed pursuant to part 55 of this chapter present at the controls.

(k) An operator or senior operator licensed pursuant to part 55 of this chapter shall be present at the controls at all times during the operation of the facility.

(l) The licensee shall designate individuals to be responsible for directing the licensed activities of licensed operators. These individuals shall be licensed as senior operators pursuant to part 55 of this chapter.

(m)(1) A senior operator licensed pursuant to part 55 of this chapter shall be present at the facility or readily available on call at all times during its operation, and shall be present at the facility during initial start-up and approach to power, recovery from an unplanned or unscheduled shut-down or significant reduction in power, and refueling, or as otherwise prescribed in the facility license.

(2) Notwithstanding any other provisions of this section, by January 1, 1984, licensees of nuclear power units shall meet the following requirements:

(i) Each licensee shall meet the minimum licensed operator staffing requirements in the following table:

MINIMUM REQUIREMENTS[1] PER SHIFT FOR ON-SITE STAFFING OF NUCLEAR POWER UNITS BY OPERATORS AND SENIOR OPERATORS LICENSED UNDER 10 CFR PART 55

Number of nuclear power units operating[2]	Position	One unit	Two units		Three units	
		One control room	One control room	Two control rooms	Two control rooms	Three control rooms
None	Senior Operator	1	1	1	1	1
	Operator	1	2	2	3	3
One	Senior Operator	2	2	2	2	2
	Operator	2	3	3	4	4
Two	Senior Operator	.....	2	3	[3]3	3
	Operator	.....	3	4	[3]5	5
Three	Senior Operator	.....	.....	.....	3	4
	Operator	.....	.....	.....	5	6

[1] Temporary deviations from the numbers required by this table shall be in accordance with criteria established in the unit's technical specifications.

[2] For the purpose of this table, a nuclear power unit is considered to be operating when it is in a mode other than cold shutdown or refueling as defined by the unit's technical specifications.

[3] The number of required licensed personnel when the operating nuclear power units are controlled from a common control room are two senior operators and four operators.

(ii) Each licensee shall have at its site a person holding a senior operator license for all fueled units at the site who is assigned responsibility for overall plant operation at all times there is

fuel in any unit. If a single senior operator does not hold a senior operator license on all fueled units at the site, then the licensee must have at the site two or more senior operators, who in combination are licensed as senior operators on all fueled units.

(iii) When a nuclear power unit is in an operational mode other than cold shutdown or refueling, as defined by the unit's technical specifications, each licensee shall have a person holding a senior operator license for the nuclear power unit in the control room at all times. In addition to this senior operator, for each fueled nuclear power unit, a licensed operator or senior operator shall be present at the controls at all times.

(iv) Each licensee shall have present, during alteration of the core of a nuclear power unit (including fuel loading or transfer), a person holding a senior operator license or a senior operator license limited to fuel handling to directly supervise the activity and, during this time, the licensee shall not assign other duties to this person.

(3) Licensees who cannot meet the January 1, 1984 deadline must submit by October 1, 1983 a request for an extension to the Director of the Office of Nuclear Regulation and demonstrate good cause for the request.

(n) The licensee shall not, except as authorized pursuant to a construction permit, make any alteration in the facility constituting a change from the technical specifications previously incorporated in a license or construction permit pursuant to § 50.36 of this part.

(o) Primary reactor containments for water cooled power reactors, other than facilities for which the certifications required under § 50.82(a)(1) have been submitted, shall be subject to the requirements set forth in appendix J to this part.

(p)(1) The licensee shall prepare and maintain safeguards contingency plan procedures in accordance with appendix C of part 73 of this chapter for effecting the actions and decisions contained in the Responsibility Matrix of the safeguards contingency plan. The licensee may make no change which would decrease the effectiveness of a security plan, or guard training and qualification plan, prepared pursuant to § 50.34(c) or part 73 of this chapter, or of the first four categories of information (Background, Generic Planning Base, Licensee Planning Base, Responsibility Matrix) contained in a licensee safeguards contingency plan prepared pursuant to § 50.34(d) or part 73 of this chapter, as applicable, without prior approval of the Commission. A licensee desiring to make such a change shall submit an application for an amendment to the licensee's license pursuant to § 50.90.

(2) The licensee may make changes to the plans referenced in paragraph (p)(1) of this section, without prior Commission approval if the changes do not decrease the safeguards effectiveness of the plan. The licensee shall maintain records of changes to the plans made without prior Commission approval for a period of three years from the date of the change, and shall submit, as specified in § 50.4, a report containing a description of each change within two months after the change is made. Prior to the safeguards contingency plan being put into effect, the licensee shall have:

(i) All safeguards capabilities specified in the safeguards contingency plan available and functional,

(ii) Detailed procedures developed according to appendix C to part 73 available at the licensee's site, and

(iii) All appropriate personnel trained to respond to safeguards incidents as outlined in the plan and specified in the detailed procedures.

(3) The licensee shall provide for the development, revision, implementation, and maintenance of its safeguards contingency plan. The licensee shall ensure that all program elements are reviewed by individuals independent of both security program management and personnel who have direct responsibility for implementation of the security program either:

(i) At intervals not to exceed 12 months, or

(ii) As necessary, based on an assessment by the licensee against performance indicators, and as soon as reasonably practicable after a change occurs in personnel, procedures, equipment, or facilities that potentially could adversely affect security, but no longer than 12 months after the change. In

any case, all elements of the safeguards contingency plan must be reviewed at least once every 24 months.

(4) The review must include a review and audit of safeguards contingency procedures and practices, an audit of the security system testing and maintenance program, and a test of the safeguards systems along with commitments established for response by local law enforcement authorities. The results of the review and audit, along with recommendations for improvements, must be documented, reported to the licensee's corporate and plant management, and kept available at the plant for inspection for a period of 3 years.

(q) A licensee authorized to possess and operate a nuclear power reactor shall follow and maintain in effect emergency plans which meet the standards in § 50.47(b) and the requirements in appendix E of this part. A licensee authorized to possess and/or operate a research reactor or a fuel facility shall follow and maintain in effect emergency plans which meet the requirements in appendix E to this part. The licensee shall retain the emergency plan and each change that decreases the effectiveness of the plan as a record until the Commission terminates the license for the nuclear power reactor. The nuclear power reactor licensee may make changes to these plans without Commission approval only if the changes do not decrease the effectiveness of the plans and the plans, as changed, continue to meet the standards of § 50.47(b) and the requirements of appendix E to this part. The research reactor and/or the fuel facility licensee may make changes to these plans without Commission approval only if these changes do not decrease the effectiveness of the plans and the plans, as changed, continue to meet the requirements of appendix E to this part. This nuclear power reactor, research reactor, or fuel facility licensee shall retain a record of each change to the emergency plan made without prior Commission approval for a period of three years from the date of the change. Proposed changes that decrease the effectiveness of the approved emergency plans may not be implemented without application to and approval by the Commission. The licensee shall submit, as specified in § 50.4, a report of each proposed change for approval. If a change is made without approval, the licensee shall submit, as specified in § 50.4, a report of each change within 30 days after the change is made.

(r) Each licensee who is authorized to possess and/or operate a research or test reactor facility with an authorized power level greater than or equal to 2 MW thermal, under a licensee of the type specified in § 50.21(c), shall submit emergency plans complying with 10 CFR part 50, appendix E, to the Director of the Office of Nuclear Reactor Regulation for approval by September 7, 1982. Each licensee who is authorized to possess and/or operate a research or test reactor facility with an authorized power level less than 2 MW thermal, under a license of the type specified in § 50.21(c), shall submit emergency plans complying with 10 CFR part 50, appendix E, to the Director of the Office of Nuclear Reactor Regulation for approval by November 3, 1982.

(s)(1) Each licensee who is authorized to possess and/or operate a nuclear power reactor shall submit to NRC within 60 days of the effective date of this amendment the radiological emergency response plans of State and local governmental entities in the United States that are wholly or partially within a plume exposure pathway EPZ, as well as the plans of State governments wholly or partially within an ingestion pathway EPZ.[1,2] These plans must be forwarded to the Director of Nuclear Reactor Regulation, by appropriate method listed in § 50.4, with a copy to the Administrator of the appropriate NRC regional office. Generally, the plume exposure pathway EPZ for nuclear power reactors shall

[1] Emergency Planning Zones (EPZs) are discussed in NUREG–0396; EPA 520/1–78–016, "Planning Basis for the Development of State and Local Government Radiological Emergency Response Plans in Support of Light Water Nuclear Power Plants," December 1978.

[2] If the State and local emergency response plans have been previously provided to the NRC for inclusion in the facility docket, the applicant need only provide the appropriate reference to meet this requirement.

consist of an area about 10 miles (16 km) in radius and the ingestion pathway EPZ shall consist of an area about 50 miles (80 km) in radius. The exact size and configuration of the EPZs for a particular nuclear power reactor shall be determined in relation to local emergency response needs and capabilities as they are affected by such conditions as demography, topography, land characteristics, access routes, and jurisdictional boundaries. The size of the EPZs also may be determined on a case-by-case basis for gas-cooled nuclear reactors and for reactors with an authorized power level less than 250 MW thermal. The plans for the ingestion pathway EPZ shall focus on such actions as are appropriate to protect the *food ingestion pathway.*

(2)(i) For operating power reactors, the licensee, State, and local emergency response plans shall be implemented by April 1, 1981, except as provided in section IV.D.3 of appendix E to this part.

(ii) If after April 1, 1981, the NRC finds that the state of emergency preparedness does not provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency *(including findings based on requirements of appendix E, section IV.D.3)* and if the deficiencies *(including deficiencies based on requirements of appendix E, section IV.D.3)* are not corrected within four months of that finding, the Commission will determine whether the reactor shall be shut down until such deficiencies are remedied or whether other enforcement action is appropriate. In determining whether a shutdown or other enforcement action is appropriate, the Commission shall take into account, among other factors, whether the licensee can demonstrate to the Commission's satisfaction that the deficiencies in the plan are not significant for the plant in question, or that adequate interim compensating actions have been or will be taken promptly, or that there are other compelling reasons for continued operation.

(3) The NRC will base its finding on a review of the FEMA findings and determinations as to whether State and local emergency plans are adequate and capable of being implemented, and on the NRC assessment as to whether the licensee's emergency plans are adequate and capable of being implemented. Nothing in this paragraph shall be construed as limiting the authority of the Commission to take action under any other regulation or authority of the Commission or at any time other than that specified in this paragraph.

(t)(1) The licensee shall provide for the development, revision, implementation, and maintenance of its emergency preparedness program. The licensee shall ensure that all program elements are reviewed by persons who have no direct responsibility for the implementation of the emergency preparedness program either:

(i) At intervals not to exceed 12 months or,

(ii) As necessary, based on an assessment by the licensee against performance indicators, and as soon as reasonably practicable after a change occurs in personnel, procedures, equipment, or facilities that potentially could adversely affect emergency preparedness, but no longer than 12 months after the change. In any case, all elements of the emergency preparedness program must be reviewed at least once every 24 months.

(2) The review must include an evaluation for adequacy of interfaces with State and local governments and of licensee drills, exercises, capabilities, and procedures. The results of the review, along with recommendations for improvements, must be documented, reported to the licensee's corporate and plant management, and retained for a period of 5 years. The part of the review involving the evaluation for adequacy of interface with State and local governments must be available to the appropriate State and local governments.

(u) Within 60 days after the effective date of this amendment, each nuclear power reactor licensee shall submit to the NRC plans for coping with emergencies that meet standards in § 50.47(b) and the requirements of appendix E to this part.

(v) Each licensee subject to the requirements of part 73 of this chapter shall ensure that physical security,

safeguards contingency and guard qualification and training plans and other related Safeguards Information are protected against unauthorized disclosure in accordance with the requirements of § 73.21 of this chapter, as appropriate.

(w) Each power reactor licensee under this part for a production or utilization facility of the type described in § 50.21(b) or § 50.22 shall take reasonable steps to obtain insurance available at reasonable costs and on reasonable terms from private sources or to demonstrate to the satisfaction of the NRC that it possesses an equivalent amount of protection covering the licensee's obligation, in the event of an accident at the licensee's reactor, to stabilize and decontaminate the reactor and the reactor station site at which the reactor experiencing the accident is located, provided that:

(1) The insurance required by paragraph (w) of this section must have a minimum coverage limit for each reactor station site of either $1.06 billion or whatever amount of insurance is generally available from private sources, whichever is less. The required insurance must clearly state that, as and to the extent provided in paragraph (w)(4) of this section, any proceeds must be payable first for stabilization of the reactor and next for decontamination of the reactor and the reactor station site. If a licensee's coverage falls below the required minimum, the licensee shall within 60 days take all reasonable steps to restore its coverage to the required minimum. The required insurance may, at the option of the licensee, be included within policies that also provide coverage for other risks, including, but not limited to, the risk of direct physical damage.

(2)(i) With respect to policies issued or annually renewed on or after April 2, 1991, the proceeds of such required insurance must be dedicated, as and to the extent provided in this paragraph, to reimbursement or payment on behalf of the insured of reasonable expenses incurred or estimated to be incurred by the licensee in taking action to fulfill the licensee's obligation, in the event of an accident at the licensee's reactor, to ensure that the reactor is in, or is returned to, and maintained in, a safe and stable condition and that radioactive contamination is removed or controlled such that personnel exposures are consistent with the occupational exposure limits in 10 CFR part 20. These actions must be consistent with any other obligation the licensee may have under this chapter and must be subject to paragraph (w)(4) of this section. As used in this section, an "accident" means an event that involves the release of radioactive material from its intended place of confinement within the reactor or on the reactor station site such that there is a present danger of release off site in amounts that would pose a threat to the public health and safety.

(ii) The stabilization and decontamination requirements set forth in paragraph (w)(4) of this section must apply uniformly to all insurance policies required under paragraph (w) of this section.

(3) The licensee shall report to the NRC on April 1 of each year the current levels of this insurance or financial security it maintains and the sources of this insurance or financial security.

(4)(i) In the event of an accident at the licensee's reactor, whenever the estimated costs of stabilizing the licensed reactor and of decontaminating the reactor and the reactor station site exceed $100 million, the proceeds of the insurance required by paragraph (w) of this section must be dedicated to and used, first, to ensure that the licensed reactor is in, or is returned to, and can be maintained in, a safe and stable condition so as to prevent any significant risk to the public health and safety and, second, to decontaminate the reactor and the reactor station site in accordance with the licensee's cleanup plan as approved by order of the Director of the Office of Nuclear Reactor Regulation. This priority on insurance proceeds must remain in effect for 60 days or, upon order of the Director, for such longer periods, in increments not to exceed 60 days except as provided for activities under the cleanup plan required in paragraphs (w)(4)(iii) and (w)(4)(iv) of this section, as the Director may find necessary to protect the public health and safety. Actions needed to bring the reactor to and maintain

the reactor in a safe and stable condition may include one or more of the following, as appropriate:

(A) Shutdown of the reactor;

(B) Establishment and maintenance of long-term cooling with stable decay heat removal;

(C) Maintenance of sub-criticality;

(D) Control of radioactive releases; and

(E) Securing of structures, systems, or components to minimize radiation exposure to onsite personnel or to the offsite public or to facilitate later decontamination or both.

(ii) The licensee shall inform the Director of the Office of Nuclear Reactor Regulation in writing when the reactor is and can be maintained in a safe and stable condition so as to prevent any significant risk to the public health and safety. Within 30 days after the licensee informs the Director that the reactor is in this condition, or at such earlier time as the licensee may elect or the Director may for good cause direct, the licensee shall prepare and submit a cleanup plan for the Director's approval. The cleanup plan must identify and contain an estimate of the cost of each cleanup operation that will be required to decontaminate the reactor sufficiently to permit the licensee either to resume operation of the reactor or to apply to the Commission under §50.82 for authority to decommission the reactor and to surrender the license voluntarily. Cleanup operations may include one or more of the following, as appropriate:

(A) Processing any contaminated water generated by the accident and by decontamination operations to remove radioactive materials;

(B) Decontamination of surfaces inside the auxiliary and fuel-handling buildings and the reactor building to levels consistent with the Commission's occupational exposure limits in 10 CFR part 20, and decontamination or disposal of equipment;

(C) Decontamination or removal and disposal of internal parts and damaged fuel from the reactor vessel; and

(D) Cleanup of the reactor coolant system.

(iii) Following review of the licensee's cleanup plan, the Director will order the licensee to complete all operations that the Director finds are necessary to decontaminate the reactor sufficiently to permit the licensee either to resume operation of the reactor or to apply to the Commission under §50.82 for authority to decommission the reactor and to surrender the license voluntarily. The Director shall approve or disapprove, in whole or in part for stated reasons, the licensee's estimate of cleanup costs for such operations. Such order may not be effective for more than 1 year, at which time it may be renewed. Each subsequent renewal order, if imposed, may be effective for not more than 6 months.

(iv) Of the balance of the proceeds of the required insurance not already expended to place the reactor in a safe and stable condition pursuant to paragraph (w)(2)(i) of this section, an amount sufficient to cover the expenses of completion of those decontamination operations that are the subject of the Director's order shall be dedicated to such use, provided that, upon certification to the Director of the amounts expended previously and from time to time for stabilization and decontamination and upon further certification to the Director as to the sufficiency of the dedicated amount remaining, policies of insurance may provide for payment to the licensee or other loss payees of amounts not so dedicated, and the licensee may proceed to use in parallel (and not in preference thereto) any insurance proceeds not so dedicated for other purposes.

(x) A licensee may take reasonable action that departs from a license condition or a technical specification (contained in a license issued under this part) in an emergency when this action is immediately needed to protect the public health and safety and no action consistent with license conditions and technical specifications that can provide adequate or equivalent protection is immediately apparent.

(y) Licensee action permitted by paragraph (x) of this section shall be approved, as a minimum, by a licensed senior operator, or, at a nuclear power reactor facility for which the certifications required under §50.82(a)(1) have been submitted, by either a licensed senior operator or a certified fuel handler, prior to taking the action.

(z) Each licensee with a utilization facility licensed pursuant to sections 103 or 104b. of the Act shall immediately notify the NRC Operations Center of the occurrence of any event specified in § 50.72 of this part.

(aa) The license shall be subject to all conditions deemed imposed as a matter of law by sections 401(a)(2) and 401(d) of the Federal Water Pollution Control Act, as amended (33 U.S.C.A. 1341 (a)(2) and (d).)

(bb) For nuclear power reactors licensed by the NRC, the licensee shall, within 2 years following permanent cessation of operation of the reactor or 5 years before expiration of the reactor operating license, whichever occurs first, submit written notification to the Commission for its review and preliminary approval of the program by which the licensee intends to manage and provide funding for the management of all irradiated fuel at the reactor following permanent cessation of operation of the reactor until title to the irradiated fuel and possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository. Licensees of nuclear power reactors that have permanently ceased operation by April 4, 1994 are required to submit such written notification by April 4, 1996. Final Commission review will be undertaken as part of any proceeding for continued licensing under part 50 or part 72 of this chapter. The licensee must demonstrate to NRC that the elected actions will be consistent with NRC requirements for licensed possession of irradiated nuclear fuel and that the actions will be implemented on a timely basis. Where implementation of such actions requires NRC authorizations, the licensee shall verify in the notification that submittals for such actions have been or will be made to NRC and shall identify them. A copy of the notification shall be retained by the licensee as a record until expiration of the reactor operating license. The licensee shall notify the NRC of any significant changes in the proposed waste management program as described in the initial notification.

(cc)(1) Each licensee shall notify the appropriate NRC Regional Administrator, in writing, immediately following the filing of a voluntary or involuntary petition for bankruptcy under any chapter of title 11 (Bankruptcy) of the United States Code by or against:

(i) The licensee;

(ii) An entity (as that term is defined in 11 U.S.C. 101(14)) controlling the licensee or listing the license or licensee as property of the estate; or

(iii) An affiliate (as that term is defined in 11 U.S.C. 101(2)) of the licensee.

(2) This notification must indicate:

(i) The bankruptcy court in which the petition for bankruptcy was filed; and,

(ii) The date of the filing of the petition.

(dd) A licensee may take reasonable action that departs from a license condition or a technical specification (contained in a license issued under this part) in a national security emergency:

(1) When this action is immediately needed to implement national security objectives as designated by the national command authority through the Commission, and

(2) No action consistent with license conditions and technical specifications that can meet national security objectives is immediately apparent.

A national security emergency is established by a law enacted by the Congress or by an order or directive issued by the President pursuant to statutes or the Constitution of the United States. The authority under this paragraph must be exercised in accordance with law, including section 57e of the Act, and is in addition to the authority granted under paragraph (x) of this section, which remains in effect unless otherwise directed by the Commission during a national security emergency.

(ee)(1) Each license issued under this part authorizing the possession of byproduct and special nuclear material produced in the operation of the licensed reactor includes, whether stated in the license or not, the authorization to receive back that same material, in the same or altered form or combined with byproduct or special nuclear material produced in the operation of another reactor of the same licensee located at that site, from a licensee of the Commission or an Agreement

State, or from a non-licensed entity authorized to possess the material.

(2) The authorizations in this subsection are subject to the same limitations and requirements applicable to the original possession of the material.

(3) This paragraph does not authorize the receipt of any material recovered from the reprocessing of irradiated fuel.

(ff) For licensees of nuclear power plants that have implemented the earthquake engineering criteria in appendix S to this part, plant shutdown is required as provided in paragraph IV(a)(3) of appendix S to this part. Prior to resuming operations, the licensee shall demonstrate to the Commission that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public and the licensing basis is maintained.

[21 FR 355, Jan. 19, 1956]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 50.54, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and on GPO Access.

§ 50.55 Conditions of construction permits.

Each construction permit shall be subject to the following terms and conditions:

(a) The permit shall state the earliest and latest dates for completion of the construction or modification.

(b) If the proposed construction or modification of the facility is not completed by the latest completion date, the permit shall expire and all rights thereunder shall be forfeited: *Provided, however,* That upon good cause shown the Commission will extend the completion date for a reasonable period of time. The Commission will recognize, among other things, developmental problems attributable to the experimental nature of the facility or fire, flood, explosion, strike, sabotage, domestic violence, enemy action, an act of the elements, and other acts beyond the control of the permit holder, as a basis for extending the completion date.

(c) Except as modified by this section and § 50.55a, the construction permit shall be subject to the same conditions to which a license is subject.

(d) At or about the time of completion of the construction or modification of the facility, the applicant will file any additional information needed to bring the original application for license up to date, and will file an application for an operating license or an amendment to an application for a license to construct and operate the facility for the issuance of an operating license, as appropriate, as specified in § 50.30(d) of this part.

(e)(1) Each individual, corporation, partnership, or other entity holding a facility construction permit subject to this part must adopt appropriate procedures to—

(i) Evaluate deviations and failures to comply to identify defects and failures to comply associated with substantial safety hazards as soon as practicable, and, except as provided in paragraph (e)(1)(ii) of this section, in all cases within 60 days of discovery, in order to identify a reportable defect or failure to comply that could create a substantial safety hazard, were it to remain uncorrected.

(ii) Ensure that if an evaluation of an identified deviation or failure to comply potentially associated with a substantial safety hazard cannot be completed within 60 days from discovery of the deviation or failure to comply, an interim report is prepared and submitted to the Commission through a director or responsible officer or designated person as discussed in paragraph (e)(7) of this section. The interim report should describe the deviation or failure to comply that is being evaluated and should also state when the evaluation will be completed. This interim report must be submitted in writing within 60 days of discovery of the deviation or failure to comply.

(iii) Ensure that a director or responsible officer of the holder of a facility construction permit subject to this part is informed as soon as practicable, and, in all cases, within the 5 working days after completion of the evaluation described in paragraph (e)(1)(i) or (e)(1)(ii) of this section, if the construction of a facility or activity, or a basic component supplied for such facility or activity—

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1A THROUGH 42-8A

JANUARY 2006 - DECEMBER 2006
FINAL TRUE-UP
DOCKET NO. 070007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI **EXHIBIT** 18
COMPANY Progress Energy Florida
WITNESS Will Garrett (WG-1)
DATE 11-06-07

PROGRESS ENERGY FLORIDA

Form 42-1A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period January 2006 through December 2006 (Form 42-2A, Line 5 + 6 + 10)	$ (14,323,932)
2	Estimated/Actual True-Up Amount approved for the period January 2006 through December 2006 (Order No. PSC-06-0972-FOF-EI)	(16,770,646)
3	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2008 to December 2008 (Lines 1 - 2)	**$ 2,446,714**

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Progress Energy Florida
Witness: Will Garrett
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Form 42-2A

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$1,767,804	$1,635,734	$ 1,605,790	$ 1,623,584	$1,870,429	$2,142,142	$2,158,030	$2,471,950	$2,319,709	$1,969,325	$1,798,306	$1,907,464	$23,270,268
2	True-Up Provision	($5,960,421)	(496,702)	(496,702)	(496,702)	(496,702)	(496,702)	(496,702)	(496,702)	(496,702)	(496,702)	(496,702)	(496,702)	(496,702)	(5,960,421)
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		1,271,102	1,139,033	1,109,088	1,126,882	1,373,727	1,645,441	1,661,329	1,975,248	1,823,007	1,472,623	1,301,604	1,410,762	17,309,847
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5A, Line 9)		1,396,747	913,381	1,540,366	2,437,223	2,099,691	3,351,208	2,130,934	2,052,156	1,795,654	2,234,712	7,447,049	3,008,975	30,408,097
	b. Capital Investment Projects (Form 42-7A, Line 9)		103,918	97,601	92,694	88,784	73,441	56,795	50,114	42,664	47,422	33,352	32,299	119,077	838,161
	c. Total Jurisdictional ECRC Costs		1,500,665	1,010,982	1,633,060	2,526,007	2,173,132	3,408,004	2,181,048	2,094,820	1,843,076	2,268,064	7,479,348	3,128,052	31,246,258
5	Over/(Under) Recovery (Line 3 - Line 4c)		(229,562)	128,050	(523,972)	(1,399,125)	(799,405)	(1,762,563)	(519,719)	(119,572)	(20,069)	(795,441)	(6,177,744)	(1,717,290)	(13,936,411)
6	Interest Provision (Form 42-3A, Line 10)		(22,255)	(21,264)	(20,808)	(23,745)	(26,870)	(31,257)	(35,350)	(34,642)	(32,608)	(32,360)	(45,524)	(60,838)	(387,521)
7	Beginning Balance True-Up & Interest Provision		(5,960,421)	(5,715,537)	(5,112,049)	(5,160,127)	(6,086,295)	(6,415,868)	(7,712,986)	(7,771,354)	(7,428,866)	(6,984,841)	(7,315,940)	(13,042,506)	(5,960,421)
	a. Deferred True-Up from January 2005 to December 2005 (Order No. PSC-05-1251-FOF-EI)		(237,170)	(237,170)	(237,170)	(237,170)	(237,170)	(237,170)	(237,170)	(237,170)	(237,170)	(237,170)	(237,170)	(237,170)	(237,170)
8	True-Up Collected/(Refunded) (see Line 2)		496,702	496,702	496,702	496,702	496,702	496,702	496,702	496,702	496,702	496,702	496,702	496,702	5,960,421
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		(5,952,707)	(5,349,219)	(5,397,297)	(6,323,465)	(6,653,038)	(7,950,156)	(8,008,524)	(7,666,036)	(7,222,011)	(7,553,110)	(13,279,676)	(14,561,102)	(14,561,102)
10	Adjustments to Period Total True-Up Including Interest (a)		0	0	0	0	0	0	0	0	0	0	0	0	0
11	End of Period Total True-Up (Lines 9 + 10)		($5,952,707)	($5,349,219)	($5,397,297)	($6,323,465)	($6,653,038)	($7,950,156)	($8,008,524)	($7,666,036)	($7,222,011)	($7,553,110)	($13,279,676)	($14,561,102)	($14,561,102)

Docket No. 070007-EI
Progress Energy Florida
Witness: Will Garrett
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Form 42-3A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Interest Provision
(in Dollars)

Line	Description	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	**($6,197,591)**	($5,952,707)	($5,349,219)	($5,397,297)	($6,323,465)	($6,653,038)	($7,950,156)	($8,008,524)	($7,666,036)	($7,222,011)	($7,553,110)	($13,279,676)	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	(5,930,452)	(5,327,955)	(5,376,489)	(6,299,720)	(6,626,168)	(7,918,899)	(7,973,174)	(7,631,394)	(7,189,403)	(7,520,750)	(13,234,152)	(14,500,264)	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	(12,128,043)	(11,280,661)	(10,725,708)	(11,697,017)	(12,949,633)	(14,571,937)	(15,923,330)	(15,639,918)	(14,855,439)	(14,742,761)	(20,787,263)	(27,779,941)	
4	Average True-Up Amount (Line 3 x 1/2)	(6,064,022)	(5,640,331)	(5,362,854)	(5,848,509)	(6,474,817)	(7,285,969)	(7,961,665)	(7,819,959)	(7,427,720)	(7,371,381)	(10,393,632)	(13,889,971)	
5	Interest Rate (First Day of Reporting Business Month)	4.30%	4.51%	4.53%	4.78%	4.96%	5.01%	5.29%	5.36%	5.27%	5.26%	5.27%	5.25%	
6	Interest Rate (First Day of Subsequent Business Month)	4.51%	4.53%	4.78%	4.96%	5.01%	5.29%	5.36%	5.27%	5.26%	5.27%	5.25%	5.27%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	8.81%	9.04%	9.31%	9.74%	9.97%	10.30%	10.65%	10.63%	10.53%	10.53%	10.52%	10.52%	
8	Average Interest Rate (Line 7 x 1/2)	4.405%	4.520%	4.655%	4.870%	4.985%	5.150%	5.325%	5.315%	5.265%	5.265%	5.260%	5.260%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.367%	0.377%	0.388%	0.406%	0.415%	0.429%	0.444%	0.443%	0.439%	0.439%	0.438%	0.438%	
10	Interest Provision for the Month (Line 4 x Line 9)	($22,255)	($21,264)	($20,808)	($23,745)	($26,870)	($31,257)	($35,350)	($34,642)	($32,608)	($32,360)	($45,524)	($60,838)	**($387,521)**

PROGRESS ENERGY FLORIDA

Form 42 4A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

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	$5,180,041	$3,596,944	$1,583,097	44.0%
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	13,633,458	16,250,943	(2,617,485)	-16.1%
	3a Pipeline Integrity Management	296,240	708,331	(412,091)	-58.2%
	4 Above Ground Tank Secondary Containment	3,600	3,310	290	8.8%
	5 SO2 Emissions Allowances	7,670,899	8,381,256	(710,357)	-8.5%
	6 Phase II Cooling Water Intake	690,723	893,003	(202,280)	-22.7%
	8 Arsenic Groundwater Standard - Base	0	0	0	0.0%
	9 Sea Turtle - Coastal Street Lighting - Distrib	36,136	108,767	(72,631)	-66.8%
	11 Modular Cooling Towers	4,635,743	4,564,195	71,548	1.6%
2	Total O&M Activities - Recoverable Costs	$32,146,839	$34,506,749	($2,359,910)	-6.8%
3	Recoverable Costs Allocated to Energy	7,670,899	8,381,256	($710,357)	-8.5%
4	Recoverable Costs Allocated to Demand	24,475,940	26,125,493	(1,649,553)	-6.3%

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)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Form 42-5A

O&M Activities
(in Dollars)

Line	Description	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$56,718	$111,511	$179,905	$1,482,001	($74,963)	$446,357	$199,038	($102,257)	$13,481	$142,621	$20,446	$678,815	$3,153,673
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	0	0	0	0	220,162	298,114	154,277	115,891	20,864	449,295	157,300	610,466	$2,026,367
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	682,613	228,061	843,087	784,638	1,250,276	2,007,766	1,016,795	1,100,567	973,484	1,085,029	2,409,995	1,251,146	13,633,458
	3a Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	4,389	11,232	25,263	17,746	12,753	28,449	23,285	96,274	12,532	13,708	10,983	39,627	296,240
	4 Above Ground Tank Secondary Containment - Intm	0	0	0	360	450	0	0	1,755	630	405	0	0	3,600
	5 SO2 Emissions Allowances	740,443	548,735	528,158	556,704	653,774	670,417	783,564	809,639	733,219	531,448	513,196	601,602	7,670,899
	6 Phase II Cooling Water Intake 316(b) - Base		67	803	732	354	376	0	0	0	0	456	11,519	14,305
	6a Phase II Cooling Water Intake 316(b) - Intm	(50,000)	86,724	52,741	65,805	22,526	82,936	61,558	63,401	96,723	97,341	52,684	43,979	676,418
	8 Arsenic Groundwater Standard - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	9 Sea Turtle - Coastal Street Lighting - Distrib	0	0	0	3,384	24,943	0	0	0	1,018	6,559	0	232	36,136
	11a Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	4,617,848	17,895	4,635,743
2	Total of O&M Activities	1,434,163	986,330	1,629,958	2,911,371	2,110,275	3,534,414	2,238,516	2,085,269	1,851,952	2,326,406	7,782,907	3,255,279	$32,146,839
3	Recoverable Costs Allocated to Energy	740,443	548,735	528,158	556,704	653,774	670,417	783,564	809,639	733,219	531,448	513,196	601,602	7,670,899
4	Recoverable Costs Allocated to Demand - Transm	56,718	111,511	179,905	1,482,001	(74,963)	446,357	199,038	(102,257)	13,481	142,621	20,446	678,815	3,153,673
	Recoverable Costs Allocated to Demand - Distrib	682,613	228,061	843,087	788,022	1,495,381	2,305,879	1,171,072	1,216,457	995,366	1,540,883	2,567,295	1,861,843	15,695,961
	Recoverable Costs Allocated to Demand - Prod-Base	0	67	803	732	354	376	0	0	0	0	4,618,303	29,414	4,650,048
	Recoverable Costs Allocated to Demand - Prod-Intm	(45,611)	97,956	78,004	83,910	35,729	111,385	84,843	161,430	109,886	111,454	63,667	83,605	976,257
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Retail Energy Jurisdictional Factor	0.96280	0.96590	0.96800	0.96840	0.97080	0.97120	0.96610	0.96980	0.96550	0.96200	0.96560	0.96700	
6	Retail Transmission Demand Jurisdictional Factor	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	
	Retail Distribution Demand Jurisdictional Factor	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
	Retail Production Demand Jurisdictional Factor - Base	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
	Retail Production Demand Jurisdictional Factor - Intm	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
	Retail Production Demand Jurisdictional Factor - Peaking	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
7	Jurisdictional Energy Recoverable Costs (A)	712,898	530,023	511,257	539,113	634,683	651,109	757,001	785,188	707,923	511,253	495,542	581,749	7,417,739
8	Jurisdictional Demand Recoverable Costs - Transm (B)	40,041	78,724	127,008	1,046,249	(52,921)	315,115	140,515	(72,191)	9,517	100,686	14,435	479,223	2,226,401
	Jurisdictional Demand Recoverable Costs - Distrib (B)	679,862	227,142	839,690	784,847	1,489,355	2,296,587	1,166,353	1,211,555	991,354	1,534,673	2,556,948	1,854,340	15,632,706
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	0	62	752	686	332	352	0	0	0	0	4,329,798	27,576	4,359,559
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	(36,054)	77,430	61,659	66,328	28,242	88,045	67,065	127,604	86,860	88,100	50,326	66,087	771,692
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,396,747	$913,381	$1,540,366	$2,437,223	$2,099,691	$3,351,208	$2,130,934	$2,052,156	$1,795,654	$2,234,712	$7,447,049	$3,008,975	$30,408,097

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

PROGRESS ENERGY FLORIDA

Form 42 6A

Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Variance Report of Capital Investment Activities
(In Dollars)

Line		(1) YTD Actual	(2) Estimated/ Actual	(3) Variance Amount	(4) Variance Percent
1	Description of Capital Investment Activities				
	3b Pipeline Integrity Management - Bartow/Anclote Pipeline	$470,321	$470,322	($1)	0.0%
	4.x Above Ground Tank Secondary Containment	$318,236	360,183	(41,947)	-11.6%
	5 SO2 Emissions Allowances	$52,228	34,866	17,362	49.8%
	7.x CAIR/CAMR	$25,710	39,447	(13,737)	-34.8%
	9 Sea Turtle - Coastal Street Lighting	$0	8,201	(8,201)	-100.0%
	10.x Underground Storage Tanks	$7,732	11,384	(3,652)	-32.1%
	11 Modular Cooling Towers	109,842	74,471	35,371	47.5%
2	Total Capital Investment Activities - Recoverable Costs	$984,069	$998,874	($14,805)	-1.5%
3	Recoverable Costs Allocated to Energy	$52,228	$34,866	$17,362	49.8%
4	Recoverable Costs Allocated to Demand	$931,841	$964,008	($32,167)	-3.3%

Notes:

Column (1) is the End of Period Totals on Form 42-7A
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Docket No. 070007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No.___(WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Form 42-7A

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Description of Investment Projects (A)													
	3b Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$39,672	$39,585	$39,498	$39,411	$39,324	$39,237	$39,150	$39,063	$38,976	$38,889	$38,802	$38,714	$470,321
	4.1 Above Ground Tank Secondary Containment - Peaking	19,822	20,066	20,940	22,989	24,775	25,874	26,653	27,014	40,364	29,941	30,376	23,700	312,514
	4.2 Above Ground Tank Secondary Containment - Base	484	482	482	480	479	478	476	475	474	472	471	469	5,722
	5 SO2 Emissions Allowances - Energy	56,353	49,262	43,339	37,373	19,741	1,484	(6,513)	(15,276)	(23,761)	(30,717)	(36,463)	(42,594)	52,228
	7.1 CAIR/CAMR - Intermediate	267	534	535	535	536	537	537	565	596	598	599	598	6,437
	7.2 CAIR - Peaking	0	0	14	96	193	319	786	1,627	2,750	3,778	4,505	5,205	19,273
	9 Sea Turtle - Coastal Street Lighting -Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0
	10.1 Underground Storage Tanks-Base	0	0	0	27	110	171	186	225	262	1,289	2,352	2,394	7,016
	10.2 Underground Storage Tanks-Intermediate	0	0	0	0	0	0	0	17	39	45	59	556	716
	11 Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	2,808	107,034	109,842
2	Total Investment Projects - Recoverable Costs	116,598	109,929	104,808	100,911	85,158	68,100	61,275	53,710	59,700	44,295	43,509	136,076	984,069
3	Recoverable Costs Allocated to Energy	56,353	49,262	43,339	37,373	19,741	1,484	(6,513)	(15,276)	(23,761)	(30,717)	(36,463)	(42,594)	52,228
	Recoverable Costs Allocated to Demand	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Recoverable Costs Allocated to Demand - Production - Base	484	482	482	507	589	649	662	700	736	1,761	5,631	109,897	122,580
	Recoverable Costs Allocated to Demand - Production - Intermediate	39,939	40,119	40,033	39,946	39,860	39,774	39,687	39,645	39,611	39,532	39,460	39,868	477,474
	Recoverable Costs Allocated to Demand - Production - Peaking	19,822	20,066	20,954	23,085	24,968	26,193	27,439	28,641	43,114	33,719	34,881	28,905	331,787
5	Retail Energy Jurisdictional Factor	0.96280	0.96590	0.96800	0.96840	0.97080	0.97120	0.96610	0.96980	0.96550	0.96200	0.96560	0.96700	
	Retail Distribution Demand Jurisdictional Factor	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
6	Retail Demand Jurisdictional Factor - Production - Base	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
7	Jurisdictional Energy Recoverable Costs (B)	54,257	47,583	41,953	36,192	19,165	1,441	(6,292)	(14,814)	(22,942)	(29,550)	(35,208)	(41,188)	50,594
	Jurisdictional Demand Recoverable Costs (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	454	452	452	475	552	608	621	656	690	1,651	5,279	103,032	114,922
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	31,570	31,712	31,644	31,576	31,508	31,440	31,371	31,338	31,311	31,248	31,192	31,514	377,424
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	17,637	17,855	18,645	20,541	22,216	23,306	24,415	25,484	38,362	30,003	31,037	25,719	295,221
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$103,918	$97,601	$92,694	$88,784	$73,441	$56,795	$50,114	$42,664	$47,422	$33,352	$32,299	$119,077	$838,161

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

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

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 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	
3	Less: Accumulated Depreciation		(89,938)	(96,781)	(103,625)	(110,468)	(117,312)	(124,155)	(130,999)	(137,842)	(144,686)	(151,529)	(158,372)	(165,214)	(172,057)	
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)		$2,584,650	2,577,806	2,570,963	2,564,119	2,557,276	2,550,432	2,543,589	2,536,745	2,529,902	2,523,058	2,516,216	2,509,373	2,502,531	
6	Average Net Investment			2,581,228	2,574,385	2,567,541	2,560,698	2,553,854	2,547,011	2,540,167	2,533,324	2,526,480	2,519,637	2,512,795	2,505,952	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		24,005	23,942	23,878	23,814	23,751	23,687	23,624	23,560	23,496	23,433	23,369	23,305	$283,865
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		4,388	4,376	4,365	4,353	4,342	4,330	4,318	4,307	4,295	4,283	4,272	4,260	51,889
8	Investment Expenses															
	a. Depreciation (C)	3.07%		6,842	6,842	6,842	6,842	6,842	6,842	6,842	6,842	6,842	6,842	6,842	6,842	82,110
	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 (D)			4,436	4,424	4,412	4,401	4,389	4,377	4,365	4,354	4,342	4,330	4,318	4,306	52,455
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			39,672	39,585	39,498	39,411	39,324	39,237	39,150	39,063	38,976	38,889	38,802	38,714	470,321
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			39,672	39,585	39,498	39,411	39,324	39,237	39,150	39,063	38,976	38,889	38,802	38,714	470,321
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)			0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)			31,359	31,290	31,222	31,153	31,084	31,015	30,947	30,878	30,809	30,740	30,671	30,602	371,770
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$31,359	$31,290	$31,222	$31,153	$31,084	$31,015	$30,947	$30,878	$30,809	$30,740	$30,671	$30,602	$371,770

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Lines 2 + 3 x 89% @ .021064 x 1/12 + 11%@ .017303 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2004 Actual Property Tax Millage Rate.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - PEAKING (Project 4.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Investments															
	a. Expenditures/Additions			$24,081	$20,339	$138,734	$233,927	$91,004	$108,912	$32,771	$33,013	$24,174	$57,250	$26,001	$378,435	$1,168,641
	b. Clearings to Plant			0	0	0	0	0	0	0	0	291,779	28,594	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		$153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	445,477	474,071	474,071	474,071	
3	Less: Accumulated Depreciation		(15,333)	(15,383)	(15,433)	(15,483)	(15,533)	(15,583)	(15,632)	(15,682)	(15,732)	(26,303)	(28,042)	(29,781)	(31,519)	
4	CWIP - Non-Interest Bearing		1,624,992	1,649,073	1,669,411	1,808,145	2,042,072	2,133,076	2,241,988	2,274,759	2,307,773	2,040,168	2,068,824	2,094,824	859,030	
5	Net Investment (Lines 2 + 3 + 4)		$1,763,357	1,787,388	1,807,677	1,946,360	2,180,238	2,271,192	2,380,054	2,412,775	2,445,738	2,459,342	2,514,853	2,539,115	1,301,582	
6	Average Net Investment			1,775,373	1,797,532	1,877,018	2,063,298	2,225,714	2,325,623	2,396,416	2,429,257	2,452,542	2,487,097	2,526,984	1,920,349	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		16,511	16,717	17,456	19,189	20,699	21,628	22,287	22,592	22,809	23,130	23,501	17,859	$244,378
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,018	3,056	3,191	3,508	3,784	3,954	4,074	4,130	4,169	4,228	4,296	3,265	44,671
8	Investment Expenses															
	a. Depreciation (C)			50	50	50	50	50	50	50	50	10,571	1,739	1,739	1,739	16,186
	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 (D)			243	243	243	243	242	242	242	242	2,815	844	841	838	7,278
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			19,822	20,066	20,940	22,989	24,775	25,874	26,653	27,014	40,364	29,941	30,376	23,700	312,514
	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			19,822	20,066	20,940	22,989	24,775	25,874	26,653	27,014	40,364	29,941	30,376	23,700	312,514
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)			0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
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)			17,637	17,855	18,632	20,455	22,045	23,022	23,716	24,037	35,915	26,641	27,028	21,088	278,072
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$17,637	$17,855	$18,632	$20,455	$22,045	$23,022	$23,716	$24,037	$35,915	$26,641	$27,028	$21,088	$278,072

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 + 3 x rate x 1/12. Based on 2004 Actual Property Tax Millage rate.
(E) Line 9a x Line 10

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)		$33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	
3	Less: Accumulated Depreciation (C)		(3,216)	(3,327)	(3,438)	(3,549)	(3,660)	(3,772)	(3,883)	(3,994)	(4,105)	(4,216)	(4,327)	(4,438)	(4,549)	
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)		$29,876	29,765	29,654	29,543	29,432	29,320	29,209	29,098	28,987	28,876	28,765	28,654	28,543	
6	Average Net Investment			29,821	29,709	29,598	29,487	29,376	29,265	29,154	29,043	28,931	28,820	28,709	28,598	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		277	276	275	274	273	272	271	270	269	268	267	266	$3,260
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		51	51	50	50	50	50	50	49	49	49	49	49	596
8	Investment Expenses															
	a. Depreciation (C)			111	111	111	111	111	111	111	111	111	111	111	111	1,334
	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 (D)			45	45	45	45	45	45	44	44	44	44	44	44	533
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			484	482	482	480	479	478	476	475	474	472	471	469	5,722
	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			484	482	482	480	479	478	476	475	474	472	471	469	5,722
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			454	452	452	450	449	448	446	445	444	443	442	440	5,365
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$454	$452	$452	$450	$449	$448	$446	$445	$444	$443	$442	$440	$5,365

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 + 3 x rate x 1/12. Based on 2004 Actual Property Tax Millage rate.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2006 through December 2006

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO2 Emission Allowance Inventory		$9,613,604	$8,873,162	$8,324,427	$7,796,268	$7,239,564	$6,585,785	$5,915,368	$5,131,804	$4,322,166	$3,588,946	$3,057,498	$2,544,302	$1,942,701	$1,942,701
	b. 25401FL Auctioned SO2 Allowance		(4,120,394)	(4,120,394)	(4,120,394)	(4,120,394)	(4,120,394)	(6,115,691)	(6,115,691)	(6,115,691)	(6,115,691)	(6,115,691)	(6,115,691)	(6,115,691)	(6,115,691)	(6,115,691)
2	Total Working Capital		$5,493,210	$4,752,768	$4,204,033	$3,675,874	$3,119,170	$470,094	($200,323)	($983,887)	($1,793,526)	($2,526,745)	($3,058,193)	($3,571,389)	($4,172,991)	($4,172,991)
3	Average Net Investment			5,122,989	4,478,400	3,939,954	3,397,522	1,794,632	134,885	(592,105)	(1,388,707)	(2,160,135)	(2,792,469)	(3,314,791)	(3,872,190)	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		47,644	41,649	36,642	31,597	16,690	1,254	(5,507)	(12,915)	(20,089)	(25,970)	(30,828)	(36,011)	$44,156
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		8,709	7,613	6,698	5,776	3,051	229	(1,007)	(2,361)	(3,672)	(4,747)	(5,635)	(6,583)	8,072
5	Total Return Component (B)			56,353	49,262	43,339	37,373	19,741	1,484	(6,513)	(15,276)	(23,761)	(30,717)	(36,463)	(42,594)	52,228
6	Expense Dr (Cr)															
	a. 5090001 SO2 allowance expense			740,443	548,735	528,158	556,704	653,774	670,417	783,564	809,639	733,219	531,448	513,196	601,602	7,670,899
7	Net Expense (C)			740,443	548,735	528,158	556,704	653,774	670,417	783,564	809,639	733,219	531,448	513,196	601,602	7,670,899
8	Total System Recoverable Expenses (Lines 5 + 7)			796,796	597,997	571,498	594,077	673,515	671,901	777,050	794,363	709,458	500,731	476,733	559,007	7,723,126
	a. Recoverable costs allocated to Energy			796,796	597,997	571,498	594,077	673,515	671,901	777,050	794,363	709,458	500,731	476,733	559,007	7,723,126
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96280	0.96590	0.96800	0.96840	0.97080	0.97120	0.96610	0.96980	0.96550	0.96200	0.96560	0.96700	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)			767,155	577,605	553,210	575,304	653,848	652,550	750,708	770,373	684,981	481,703	460,333	540,560	7,468,333
12	Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$767,155	$577,605	$553,210	$575,304	$653,848	$652,550	$750,708	$770,373	$684,981	$481,703	$460,333	$540,560	$7,468,333

Notes:
(A) Lines 3 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 Rate Case Settlement in Dkt. 050078-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9.
(E) Line 8b x Line 10.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Intermediate (Project 7.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Investments															
	a. Expenditures/Additions			$48,503	$138	$27	$0	$162	$0	$0	$5,144	$355	$95	$0	($96)	$54,328
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	48,503	48,641	48,668	48,668	48,830	48,830	48,830	53,974	54,329	54,423	54,423	54,328	
5	Net Investment (Lines 2+ 3 + 4)		$0	48,503	48,641	48,668	48,668	48,830	48,830	48,830	53,974	54,329	54,423	54,423	54,328	
6	Average Net Investment			24,252	48,572	48,655	48,668	48,749	48,830	48,830	51,402	54,151	54,376	54,423	54,376	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		226	452	452	453	453	454	454	478	504	506	506	506	$5,443
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		41	83	83	83	83	83	83	87	92	92	93	92	995
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			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	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)			267	534	535	535	536	537	537	565	596	598	599	598	6,437
	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			267	534	535	535	536	537	537	565	596	598	599	598	6,437
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 (Intm)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			250	501	502	502	503	503	503	530	559	561	562	561	6,035
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$250	$501	$502	$502	$503	$503	$503	$530	$559	$561	$562	$561	$6,035

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 + 3 x rate x 1/12. Based on 2004 Actual Property Tax Millage rate.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Peaking (Project 7.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$2,504	$12,394	$5,322	$17,493	$67,462	$85,428	$118,788	$68,184	$63,938	$63,315	$504,830
	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		$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	2,504	14,898	20,221	37,714	105,176	190,604	309,392	377,576	441,514	504,830	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	2,504	14,898	20,221	37,714	105,176	190,604	309,392	377,576	441,514	504,830	
6	Average Net Investment			0	0	1,252	8,701	17,559	28,967	71,445	147,890	249,998	343,484	409,545	473,172	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		0	0	12	81	163	269	664	1,375	2,325	3,194	3,809	4,400	$16,294
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	2	15	30	49	121	251	425	584	696	804	2,978
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			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	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	14	96	193	319	786	1,627	2,750	3,778	4,505	5,205	19,273
	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	14	96	193	319	786	1,627	2,750	3,778	4,505	5,205	19,273
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)			0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
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)			0	0	12	85	172	284	699	1,448	2,447	3,362	4,009	4,631	17,149
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$12	$85	$172	$284	$699	$1,448	$2,447	$3,362	$4,009	$4,631	$17,149

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 + 3 x rate x 1/12. Based on 2004 Actual Property Tax Millage rate.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base - AFUDC (Project 7.3)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$253,064	$672,286	$798,204	$840,661	$882,154	$850,724	$769,880	$2,455,993	$2,123,779	$2,673,126	$4,999,216	$6,832,388	$23,951,475
	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 (B) 8.848%		14,421	17,939	23,492	29,707	36,278	42,196	47,745	59,990	77,316	95,571	124,561	169,098	
2	Plant-in-Service/Depreciation Base	$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-AFUDC Interest Bearing Accrual	1,829,277	2,096,762	2,786,987	3,608,683	4,479,052	5,397,483	6,090,404	6,908,029	9,424,011	11,625,106	14,393,803	19,517,579	26,519,066	
5	Net Investment (Lines 2 + 3 + 4)	$1,829,277	2,096,762	2,786,987	3,608,683	4,479,052	5,397,483	6,090,404	6,908,029	9,424,011	11,625,106	14,393,803	19,517,579	26,519,066	
6	Average Net Investment		1,963,020	2,441,875	3,197,835	4,043,868	4,938,268	5,743,944	6,499,216	8,166,020	10,524,558	13,009,454	16,955,691	23,018,322	
7	Return on Average Net Investment									0					
	a. Equity Component Grossed Up For Taxes		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.04% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		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)		0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
12	Retail Energy-Related Recoverable Costs		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) This schedule shown for informational purposes.
(B) AFUDC calculation based on 2005 Rate Case Settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 4.59%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.019292		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		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 - (Distribution)		0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
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)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 + 3 x rate x 1/12. Based on 2004 Actual Property Tax Millage rate.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

Docket No. 070007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No.___(WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - BASE (Project 10.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$4,919	$10,172	$950	$1,710	$5,461	$1,149	$185,685	$7,554	$40	$217,641
	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		$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	4,919	15,091	16,041	17,751	23,212	24,362	210,047	217,601	217,641	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	4,919	15,091	16,041	17,751	23,212	24,362	210,047	217,601	217,641	
6	Average Net Investment			0	0	0	2,460	10,005	15,566	16,896	20,482	23,787	117,204	213,824	217,621	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		0	0	0	23	93	145	157	190	221	1,090	1,989	2,024	$5,932
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	4	17	26	29	35	40	199	364	370	1,084
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			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	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	27	110	171	186	225	262	1,289	2,352	2,394	7,016
	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	27	110	171	186	225	262	1,289	2,352	2,394	7,016
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			0	0	0	25	103	160	174	211	246	1,208	2,205	2,244	6,578
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$25	$103	$160	$174	$211	$246	$1,208	$2,205	$2,244	$6,578

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 + 3 x rate x 1/12. Based on 2004 Actual Property Tax Millage rate.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 through December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - INTERMEDIATE (10.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$3,040	$1,017	$102	$2,480	$87,760	$94,398
	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		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	0	0	0	3,040	4,057	4,158	6,638	94,398	
6	Average Net Investment			0	0	0	0	0	0	0	1,520	3,548	4,107	5,398	50,518	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		0	0	0	0	0	0	0	14	33	38	50	470	$605
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	0	3	6	7	9	86	111
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			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	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	17	39	45	59	556	716
	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	17	39	45	59	556	716
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)			0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)			0	0	0	0	0	0	0	13	31	36	47	439	566
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$0	$13	$31	$36	$47	$439	$566

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 + 3 x rate x 1/12. Based on 2004 Actual Property Tax Millage rate.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: MODULAR COOLING TOWERS - BASE (Project 11)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 06	Actual February 06	Actual March 06	Actual April 06	Actual May 06	Actual June 06	Actual July 06	Actual August 06	Actual September 06	Actual October 06	Actual November 06	Actual December 06	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$510,553	$5,668	$516,221
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	516,221	
	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		$0	0	0	0	0	0	0	0	0	0	0	0	516,221	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(64,528)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	510,553	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	0	0	0	0	0	0	510,553	451,693	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	255,277	481,123	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		0	0	0	0	0	0	0	0	0	0	2,374	31,371	$33,746
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	0	0	0	0	434	5,735	6,169
8	Investment Expenses															
	a. Depreciation (C)	20.00%		0	0	0	0	0	0	0	0	0	0	0	64,528	64,528
	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 (D)	0.018008		0	0	0	0	0	0	0	0	0	0	0	5,400	5,400
	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	2,808	107,034	109,842
	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	2,808	107,034	109,842
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			0	0	0	0	0	0	0	0	0	0	2,633	100,348	102,980
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,633	$100,348	$102,980

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 5 year life of project, as stated in Dkt. 060162-EI.
(D) Line 2 + 3 x rate x 1/12. Based on 2004 Actual Property Tax Millage rate.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 Rate Case Settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
CAPITAL PROGRAM DETAIL

JANUARY 2006 - DECEMBER 2006
FINAL TRUE-UP
DOCKET NO. 070007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI **EXHIBIT** 19
COMPANY Progress Energy Florida
WITNESS Will Garrett (WG-2)
DATE 11-06-07

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$4,752	$5,133	$14,486	$24,174	$1,402	$0	$0	$49,948
	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	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	623,792	623,792	623,792	623,792	623,792	623,792	628,544	633,677	648,163	672,338	673,740	673,740	673,740	
5	Net Investment (Lines 2 + 3 + 4)	$623,792	623,792	623,792	623,792	623,792	623,792	628,544	633,677	648,163	672,338	673,740	673,740	673,740	
6	Average Net Investment		623,792	623,792	623,792	623,792	623,792	626,168	631,111	640,920	660,251	673,039	673,740	673,740	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		5,801	5,801	5,801	5,801	5,801	5,823	5,869	5,961	6,140	6,259	6,266	6,266	$71,591
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		1,060	1,060	1,060	1,060	1,060	1,064	1,073	1,090	1,122	1,144	1,145	1,145	13,088
8	Investment Expenses														
	a. Depreciation 1.83%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.021580		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)		6,862	6,862	6,862	6,862	6,862	6,888	6,942	7,050	7,263	7,403	7,411	7,411	84,677
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		$6,862	$6,862	$6,862	$6,862	$6,862	$6,888	$6,942	$7,050	$7,263	$7,403	$7,411	$7,411	$84,677

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	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	$153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	
3	Less: Accumulated Depreciation	(15,333)	(15,383)	(15,433)	(15,483)	(15,533)	(15,583)	(15,632)	(15,682)	(15,732)	(19,148)	(19,572)	(19,996)	(20,420)	
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)	$138,365	138,315	138,265	138,215	138,165	138,115	138,066	138,016	137,966	134,550	134,126	133,702	133,278	
6	Average Net Investment		138,340	138,290	138,240	138,190	138,140	138,090	138,041	137,991	136,258	134,338	133,914	133,490	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,287	1,286	1,286	1,285	1,285	1,284	1,284	1,283	1,267	1,249	1,245	1,241	$15,283
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		235	235	235	235	235	235	235	235	232	228	228	227	2,794
8	Investment Expenses														
	a. Depreciation 3.31%		50	50	50	50	50	50	50	50	3,416	424	424	424	5,087
	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 0.021084		243	243	243	243	242	242	242	242	236	235	235	234	2,880
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,814	1,814	1,813	1,813	1,812	1,811	1,811	1,810	5,151	2,137	2,132	2,126	26,044
	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		$1,814	$1,814	$1,813	$1,813	$1,812	$1,811	$1,811	$1,810	$5,151	$2,137	$2,132	$2,126	$26,044

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2006 through December 2006
Above Ground Tank Secondary Containment (Projects 4.1 and 4.2 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(In Dollars)

Base

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	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	$33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	
3	Less: Accumulated Depreciation	(3,216)	(3,327)	(3,438)	(3,549)	(3,660)	(3,772)	(3,883)	(3,994)	(4,105)	(4,216)	(4,327)	(4,438)	(4,549)	
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)	$29,876	29,765	29,654	29,543	29,432	29,320	29,209	29,098	28,987	28,876	28,765	28,654	28,543	
6	Average Net Investment		29,821	29,709	29,598	29,487	29,376	29,265	29,154	29,043	28,931	28,820	28,709	28,598	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		277	276	275	274	273	272	271	270	269	268	267	266	$3,260
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		51	51	50	50	50	50	50	49	49	49	49	49	596
8	Investment Expenses														
	a. Depreciation 4.03%		111	111	111	111	111	111	111	111	111	111	111	111	1,334
	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 0.018008		45	45	44	44	44	44	44	43	43	43	43	43	525
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		484	482	481	480	478	477	475	474	473	471	470	469	5,714
	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		$484	$482	$481	$480	$478	$477	$475	$474	$473	$471	$470	$469	35,714

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(In Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$83,493	$172,936	$55,368	$104,160	$27,054	$18,527	$0	$26,984	$0	$220,000	$708,521
	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		
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0		
4	CWIP - Non-Interest Bearing	905,709	905,709	905,709	989,202	1,162,138	1,217,506	1,321,666	1,348,720	1,367,247	1,367,247	1,394,230	1,394,230		
5	Net Investment (Lines 2 + 3 + 4)	$905,709	905,709	905,709	989,202	1,162,138	1,217,506	1,321,666	1,348,720	1,367,247	1,367,247	1,394,230	1,394,230	0	
6	Average Net Investment		905,709	905,709	947,455	1,075,670	1,189,822	1,269,586	1,335,193	1,357,983	1,367,247	1,380,738	1,394,230	697,115	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		8,423	8,423	8,811	10,004	11,065	11,807	12,417	12,629	12,715	12,841	12,966	6,483	$128,586
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		1,540	1,540	1,611	1,829	2,023	2,158	2,270	2,309	2,324	2,347	2,370	1,185	23,505
8	Investment Expenses														
	a. Depreciation 3.39%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.015717		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)		9,963	9,963	10,422	11,832	13,088	13,965	14,687	14,938	15,040	15,188	15,337	7,668	152,091
	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		$9,963	$9,963	$10,422	$11,832	$13,088	$13,965	$14,687	$14,938	$15,040	$15,188	$15,337	$7,668	$152,091

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2006 through December 2006
Above Ground Tank Secondary Containment (Projects 4.1 and 4.2 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$715	$0	$52,815	$60,991	$32,611	$0	$0	$0	$0	$28,594	$0	$0	$175,126
	b. Clearings to Plant		0	0	0	0	0	0	0	0	150,344	28,594	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	150,344	178,938	178,938	178,938	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	(874)	(1,395)	(1,915)	(2,435)	
4	CWIP - Non-Interest Bearing	3,812	4,527	4,527	57,342	118,333	150,344	150,344	150,344	150,344	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$3,812	4,527	4,527	57,342	118,333	150,344	150,344	150,344	150,344	149,469	177,543	177,023	176,502	
6	Average Net Investment		4,170	4,527	30,935	87,837	134,338	150,344	150,344	150,344	149,907	163,506	177,283	176,763	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		39	42	288	817	1,249	1,398	1,398	1,398	1,394	1,521	1,649	1,644	$12,837
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		7	8	53	149	228	256	256	256	255	278	301	300	2,347
8	Investment Expenses														
	a. Depreciation 3.49%		0	0	0	0	0	0	0	0	874	520	520	520	2,435
	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 0.024806		0	0	0	0	0	0	0	0	619	367	368	365	1,717
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		46	50	340	966	1,478	1,654	1,654	1,654	3,142	2,686	2,836	2,830	19,336
	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		$46	$50	$340	$966	$1,478	$1,654	$1,654	$1,654	$3,142	$2,686	$2,836	$2,830	$19,336

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,371	$150,710	$176,081
	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	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	25,371	176,081	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	25,371	176,081	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	12,685	100,726	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	0	0	0	0	118	937	$1,055
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	0	0	0	0	0	0	0	0	22	171	193
8	Investment Expenses														
	a. Depreciation 2.66%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.022088		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	140	1,108	1,248
	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	$140	$1,108	$1,248

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2006 through December 2006
Above Ground Tank Secondary Containment (Projects 4.1 and 4.2 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(In Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$270	$630	$7,725	$8,625
	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	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	270	900	8,625	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	270	900	8,625	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	135	585	4,763	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	0	0	0	1	5	44	$51
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	0	0	0	0	0	0	0	0	1	8	9
8	Investment Expenses														
	a. Depreciation 3.20%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.018186		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	1	6	52	60
	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	$6	$52	$60

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(In Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$584	$0	$0	$0	$0	$0	$584
	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	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	584	584	584	584	584	584	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	584	584	584	584	584	584	
6	Average Net Investment		0	0	0	0	0	0	292	584	584	584	584	584	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	3	5	5	5	5	5	$30
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	0	0	0	0	0	1	1	1	1	1	5
8	Investment Expenses														
	a. Depreciation 2.33%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.018518		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	3	6	6	6	6	6	35
	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	$3	$6	$6	$6	$6	$6	$35

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Unitversity of Florida (Project 4.1h)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$23,365	$20,339	$2,428	$0	$3,626	$0	$0	$0	$0	$0	$0	$0	$49,756
	b. Clearings to Plant		0	0	0	0	0	0	0	0	141,435	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	141,435	141,435	141,435	141,435	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	(6,280)	(7,075)	(7,869)	(8,664)	
4	CWIP - Non-Interest Bearing	91,679	115,044	135,383	137,809	137,809	141,435	141,435	141,435	141,435	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$91,679	115,044	135,383	137,809	137,809	141,435	141,435	141,435	141,435	135,154	134,360	133,566	132,771	
6	Average Net Investment		103,362	125,214	136,596	137,809	139,622	141,435	141,435	141,435	138,295	134,757	133,963	133,168	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		961	1,164	1,270	1,282	1,298	1,315	1,315	1,315	1,286	1,253	1,246	1,238	$14,945
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		176	213	232	234	237	240	240	240	235	229	228	226	2,732
8	Investment Expenses														
	a. Depreciation 6.74%		0	0	0	0	0	0	0	0	6,280	794	794	794	8,664
	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 0.021590		0	0	0	0	0	0	0	0	1,960	242	240	239	2,681
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,137	1,377	1,503	1,516	1,536	1,556	1,556	1,556	9,762	2,518	2,508	2,498	29,022
	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		$1,137	$1,377	$1,503	$1,516	$1,536	$1,556	$1,556	$1,556	$9,762	$2,518	$2,508	$2,498	$29,022

For Project: CAIR/CAMR - CRYSTAL RIVER SOUTH - 1 & 2 (Project 7.3a)
(in Dollars)

Calculated @ AFUDC - Not applicable to ECRC revenue reqmts. until placed in service.

Line	Description	Base	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,783	$9,804	$14,587
	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	9.848%		0	0	0	0	0	0	0	0	0	0	16	72	89
2	Plant-in-Service/Depreciation Base		$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 - AFUDC-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	4,800	14,676	14,676
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	0	0	0	0	0	0	4,800	14,676	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	2,400	9,738	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Tax	6.819%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.029% x 1/1	2.029%		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.19%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.018008		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

For Project: CAIR/CAMR - CRYSTAL RIVER NORTH - 4 & 5 (Project 7.3b)
(in Dollars)

Calculated @ AFUDC - Not applicable to ECRC revenue reqmts. until placed in service.

Line	Description	Base	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments															
	a. Expenditures/Additions			$253,064	$672,286	$798,204	$840,661	$852,154	$850,724	$789,880	$2,455,993	$2,123,778	$2,673,129	$4,994,433	$6,822,584	$20,936,888
	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	9.848%		14,421	17,939	23,492	29,707	36,278	42,196	47,745	59,990	77,316	95,571	124,543	169,027	738,224
2	Plant-in-Service/Depreciation Base		$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 - AFUDC-Interest Bearing		1,829,277	2,096,762	2,786,987	3,608,683	4,479,052	5,397,483	6,090,404	6,906,029	9,424,011	11,625,106	14,393,803	19,512,779	26,504,389	24,675,112
5	Net Investment (Lines 2 + 3 + 4)		$1,829,277	2,096,762	2,786,987	3,608,683	4,479,052	5,397,483	6,090,404	6,906,029	9,424,011	11,625,106	14,393,803	19,512,779	26,504,389	
6	Average Net Investment			1,963,020	2,441,875	3,197,835	4,043,868	4,938,268	5,743,944	6,499,216	8,166,020	10,524,558	13,009,454	16,953,291	23,008,584	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Tax	6.819%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.029% x 1/1	2.029%		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.27%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.018008		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

For Project: CAIR/CAMR - ANCLOTE (Project 7.1a)
(in Dollars)

Line	Intermediate Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$48,503	$138	$27	$0	$162	$0	$0	$5,144	$355	$53	$0	($99)	$54,328
	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	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	48,503	48,641	48,668	48,668	48,830	48,830	48,830	53,974	54,329	54,423	54,423	54,328	
5	Net Investment (Lines 2 + 3 + 4)	$0	48,503	48,641	48,668	48,668	48,830	48,830	48,830	53,974	54,329	54,423	54,423	54,328	
6	Average Net Investment		24,252	48,572	48,655	48,668	48,749	48,830	48,830	51,402	54,151	54,376	54,423	54,376	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Tax 11.16%		226	452	452	453	453	454	454	478	504	506	506	506	$5,443
	b. Debt Component (Line 6 x 2.57% x 1/12 2.04%		41	83	83	83	83	83	83	87	92	92	93	92	985
8	Investment Expenses														
	a. Depreciation 2.21%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.017303		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)		267	534	535	535	536	537	537	565	596	598	599	598	6,428
	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		$267	$534	$535	$535	$536	$537	$537	$565	$596	$598	$599	$598	$6,428

For Project: CAIR/CAMR - BARTOW (Project 7.1b)
This site not applicable- No costs associated to this site for this project for years 2006 thru 2014 per 2006 and 2007 projection filing. Confirmed by Regulatory Planning.
Intermediate

For Project: CAIR/CAMR - SUWANNEE (Project 7.1c)
This site not applicable- No costs associated to this site for this project for years 2006 thru 2014 per 2006 and 2007 projection filing. Confirmed by Regulatory Planning.
Intermediate

ALL Peaking

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$99	$236	$1,737	$559	$1,845	$2,753	$0	$9,581	$16,811
	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	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	99	335	2,072	2,631	4,276	7,030	7,030	16,611	
6	Average Net Investment		0	0	0	0	49	217	1,203	2,352	3,454	5,653	7,030	11,820	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	2	11	22	32	53	65	110	$296
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	0	0	0	0	2	4	6	10	12	20	54
8	Investment Expenses														
	a. Depreciation 1.80%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.024805		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	1	2	13	26	38	62	77	130	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		$0	$0	$0	$0	$1	$2	$13	$26	$38	$62	$77	$130	$350

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$1,504	$7,127	$2,758	$7,070	$28,550	$17,633	$48,186	$9,710	$11,211	$23,978	$157,927
	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	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	1,504	8,632	11,389	18,460	47,009	64,643	113,027	122,737	133,948	157,927	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	1,504	8,632	11,389	18,460	47,009	64,643	113,027	122,737	133,948	157,927	
6	Average Net Investment		0	0	752	5,068	10,010	14,924	32,734	55,826	88,835	117,882	128,343	145,938	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	7	47	93	139	304	520	827	1,096	1,194	1,357	$5,585
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	1	9	17	25	56	95	151	200	218	248	1,021
8	Investment Expenses														
	a. Depreciation 4.26%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.021064		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	8	56	110	164	360	615	978	1,297	1,412	1,605	6,606
	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	$8	$56	$110	$164	$360	$615	$978	$1,297	$1,412	$1,605	$6,606

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$1,000	$5,267	$2,466	$8,038	$12,969	$42,489	$16,156	$7,280	$2,124	$2,668	$100,476
	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	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	1,000	6,267	8,732	16,770	29,758	72,247	88,405	95,684	97,808	100,476	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	1,000	6,267	8,732	16,770	29,758	72,247	88,405	95,684	97,808	100,476	
6	Average Net Investment		0	0	500	3,633	7,499	12,751	23,264	51,003	80,326	92,044	96,746	99,142	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	5	34	70	119	216	474	747	856	900	922	$4,342
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	1	6	13	22	40	87	137	156	164	169	794
8	Investment Expenses														
	a. Depreciation 3.04%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.022068		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	6	40	82	140	256	561	884	1,012	1,064	1,091	5,136
	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	$6	$40	$82	$140	$256	$561	$884	$1,012	$1,064	$1,091	$5,136

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,937	$455	$277	$3,669
	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	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	2,937	3,392	3,669	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	2,937	3,392	3,669	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	1,468	3,164	3,530	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	0	0	0	14	29	33	$76
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	0	0	0	0	0	0	0	2	6	6	14
8	Investment Expenses														
	a. Depreciation 2.98%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.018518		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	16	35	39	90
	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	$16	$35	$39	$90

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - January 2006 through December 2006
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$4,075	$2,660	$4,267	$30,598	$46,692	$1,595	$89,885
	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	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	4,075	6,735	11,001	41,599	88,291	89,885	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	4,075	6,735	11,001	41,599	88,291	89,885	
6	Average Net Investment		0	0	0	0	0	0	2,037	5,405	8,868	26,300	64,945	89,088	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	19	50	82	245	604	829	$1,829
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	0	0	0	0	3	9	15	45	110	151	334
8	Investment Expenses														
	a. Depreciation 3.90%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.019746		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	22	59	96	289	714	980	2,163
	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	$22	$59	$96	$289	$714	$980	$2,163

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$20,112	$21,362	$46,101	$8,026	$316	$24,761	$120,680
	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	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	20,112	41,474	87,575	95,603	95,919	120,680	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	20,112	41,474	87,575	95,603	95,919	120,680	
6	Average Net Investment		0	0	0	0	0	0	10,056	30,793	64,524	91,589	95,761	108,300	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	94	286	600	852	891	1,007	$3,730
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	0	0	0	0	17	52	110	156	163	184	682
8	Investment Expenses														
	a. Depreciation 5.33%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.015717		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	111	339	710	1,007	1,053	1,191	4,411
	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	$111	$339	$710	$1,007	$1,053	$1,191	$4,411

For Project: CAIR CTs - TURNER (Project 7.2g)
(In Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$649	$0	$525	$623	$3,758	$600	$90	$6,245
	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	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	649	649	1,174	1,797	5,555	6,155	6,245	
6	Average Net Investment		0	0	0	0	0	325	649	912	1,486	3,676	5,855	6,200	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	3	6	8	14	34	54	58	$178
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	0	0	0	1	1	2	3	8	10	11	32
8	Investment Expenses														
	a. Depreciation 4.82%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.021560		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	4	7	10	16	40	64	68	210
	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	$4	$7	$10	$16	$40	$64	$68	$210

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(In Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$1,500	$0	$0	$1,811	$3,121	$2,540	$384	$9,336
	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	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	1,500	1,500	1,500	3,311	6,431	8,971	9,336	
6	Average Net Investment		0	0	0	0	0	750	1,500	1,500	2,405	4,871	7,701	9,154	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	7	14	14	22	45	72	85	$259
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	0	0	0	1	3	3	4	8	13	16	47
8	Investment Expenses														
	a. Depreciation 4.29%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.018166		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	8	17	17	26	54	85	101	307
	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	$8	$17	$17	$26	$54	$85	$101	$307

For Project: UNDERGROUND STORAGE TANKS - CRYSTAL RIVER 4 & 5 (Project 10a)
(in Dollars)

Base

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$4,919	$10,172	$950	$1,710	$5,451	$1,149	$185,685	$7,554	$40	$217,641
	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	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	4,919	15,091	16,041	17,751	23,212	24,362	210,047	217,601	217,641	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	4,919	15,091	16,041	17,751	23,212	24,362	210,047	217,601	217,641	
6	Average Net Investment		0	0	0	2,460	10,005	15,566	16,896	20,482	23,787	117,204	213,824	217,621	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxe 11.16%		0	0	0	23	93	145	157	190	221	1,090	1,989	2,024	$5,932
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	4	17	26	29	35	40	199	364	370	1,084
8	Investment Expenses														
	a. Depreciation 3.27%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.015008		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	27	110	171	186	225	262	1,289	2,352	2,394	7,016
	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	$27	$110	$171	$186	$225	$262	$1,289	$2,352	$2,394	$7,016

For Project: UNDERGROUND STORAGE TANKS - BARTOW (Project 10b)
(in Dollars)

Intermediate

Line	Description	Beginning of Period Amount	Actual Jan-06	Actual Feb-06	Actual Mar-06	Actual Apr-06	Actual May-06	Actual Jun-06	Actual Jul-06	Actual Aug-06	Actual Sep-06	Actual Oct-06	Actual Nov-06	Actual Dec-06	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$3,040	$1,017	$102	$2,460	$87,780	$94,398
	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	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	3,040	4,057	4,158	6,638	94,398	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	3,040	4,057	4,158	6,638	94,398	
6	Average Net Investment		0	0	0	0	0	0	0	1,520	3,548	4,107	5,398	50,518	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxe 11.16%		0	0	0	0	0	0	0	14	33	38	50	470	$605
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	0	0	0	0	3	6	7	9	86	111
8	Investment Expenses														
	a. Depreciation 3.19%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.021064		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	17	39	45	59	556	716
	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	$17	$39	$45	$59	$556	$716

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
2008 CAIR/CAMR Projects Summary

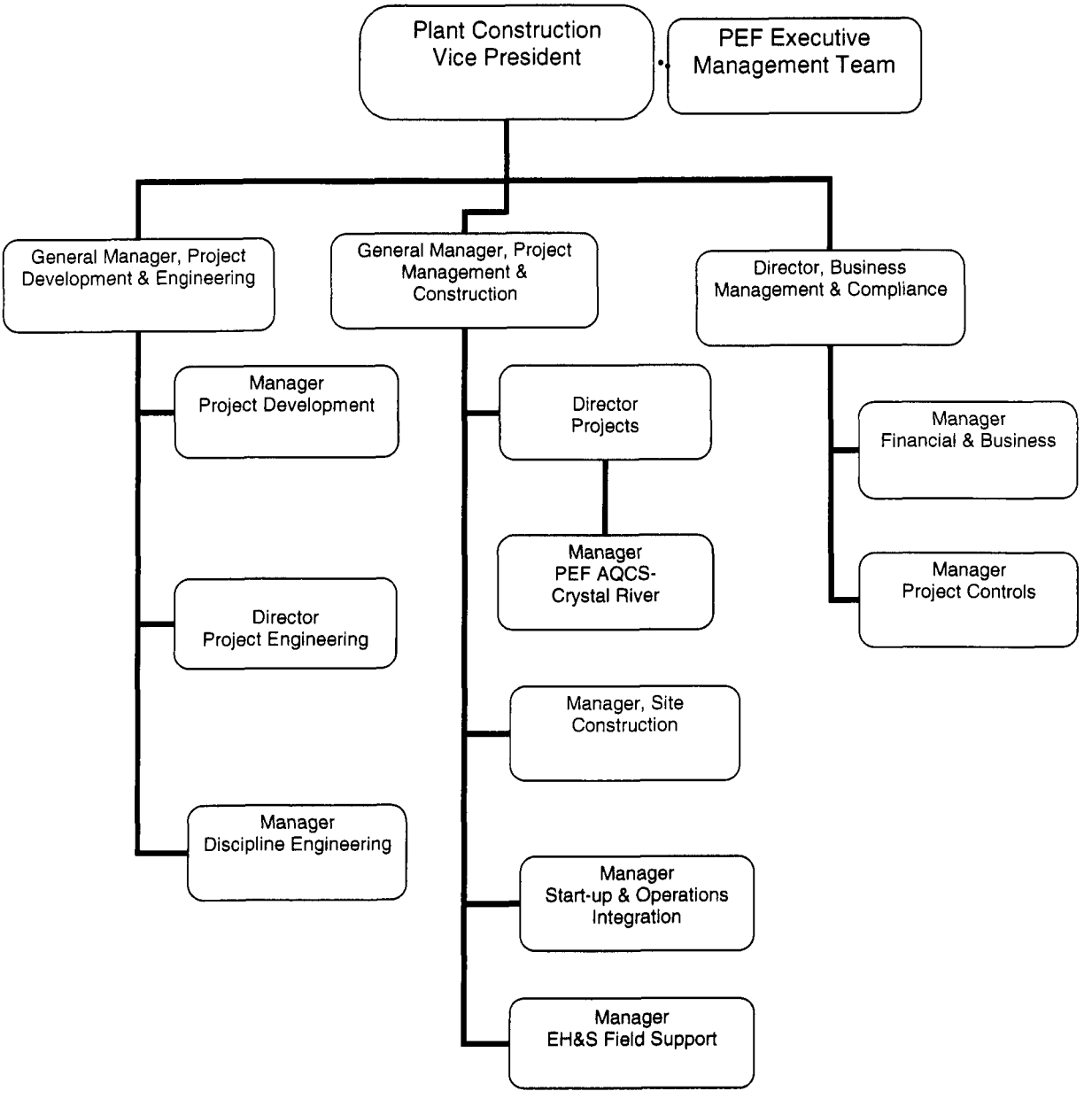
Project	Jan 2008	Feb 2008	Mar 2008	Apr 2008	May 2008	June 2008	July 2008	Aug 2008	Sep 2008	Oct 2008	Nov 2008	Dec 2008	Total
AFUDC Bearing Capital Expenditures													
CR Unit 4 FGD	$ 10,165,315	$ 9,174,920	$ 10,753,998	$ 9,231,154	$ 8,982,987	$ 8,764,726	$ 8,507,330	$ 7,405,689	$ 7,102,095	$ 6,572,477	$ 7,073,628	$ 5,974,620	$ 99,708,938
CR Unit 4 SCR	2,594,903	4,614,760	2,451,448	2,490,036	2,431,888	2,460,923	4,626,617	2,342,628	2,624,065	3,639,505	2,666,281	2,302,930	35,245,984
CR Unit 5 SCR	3,054,581	3,266,804	2,920,972	2,952,083	2,913,956	4,409,867	4,363,511	3,223,789	3,186,670	4,095,474	2,851,433	4,152,023	41,391,163
CR Unit 5 FGD	11,270,851	10,775,505	11,532,751	9,444,123	10,088,749	9,253,249	8,740,745	7,832,580	7,776,620	7,179,229	7,668,536	6,504,231	108,067,169
CR Common	27,907,595	27,711,296	25,564,373	24,794,297	24,238,184	24,274,367	24,047,747	23,026,769	22,413,993	20,859,388	21,926,499	18,744,242	285,508,750
Total (1)	**$ 54,993,245**	**$ 55,543,285**	**$ 53,223,543**	**$ 48,911,693**	**$ 48,655,764**	**$ 49,163,131**	**$ 50,285,949**	**$ 43,831,455**	**$ 43,103,444**	**$ 42,346,073**	**$ 42,186,376**	**$ 37,678,046**	**$ 569,922,004**
Non AFUDC Bearing Capital Expenditures													
Crystal River Units 1,2,4,5 CMMS	$ -	$ -	$ -	$ -	$ -	$ -	$ 156,410	$ 203,660	$ 156,410	$ 369,114	$ 1,357,645	$ 450,069	$ 2,693,309
Anclote LNB's	$ 30,000	$ 30,000	$ 50,000	$ 40,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 40,000	$ 10,000	$ -	$ 300,000

Notes:
(1) Total does not include AFUDC.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 20
COMPANY Progress Energy Florida
WITNESS Patricia Q. West (PW-1)
DATE 11-26-07

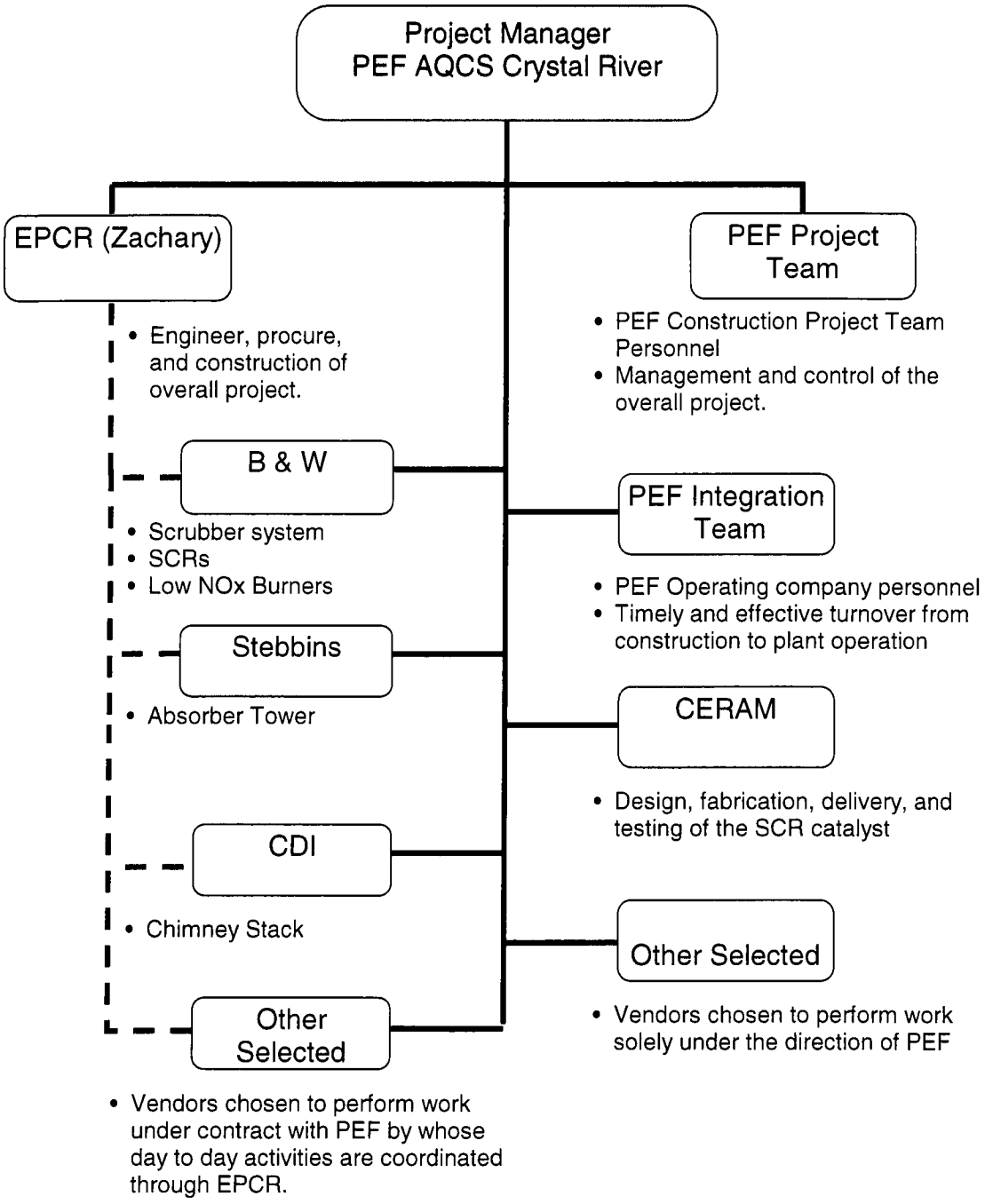
Docket No. 070007-EI
Progress Energy Florida
Witness: P. West
Exhibit No. ___ (PW-1)
Page 1 of 1

Docket No. 07007-EI
Progress Energy Florida
Witness: Thomas Cornell
Exhibit No. __ (TC-1)
Integrated Clean Air Compliance Plan
Organizational Structure



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI **EXHIBIT** 21
COMPANY Progress Energy Florida
WITNESS Thomas Cornell (TC-1)
DATE 11-06-07

Docket No. 07007-EI
Progress Energy Florida
Witness: Thomas Cornell
Exhibit No. __ (TC-2)
Crystal River Air Quality Control Projects
Organizational Structure



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 22
COMPANY Progress Energy Florida
WITNESS Thomas Cornell (TC-2)
DATE 11-06-07

COMPOSITE EXHIBIT NO. __ (TC-3)

REDACTED IN FULL

Progress Energy Florida, Inc., Crystal River Unit 4 and Unit 5, Letter of Intent, November 2, 2006

Progress Energy Florida, Inc., Crystal River Unit 4 and Unit 5, Letter of Intent dated November 2, 2006, Amendment 1, December 12, 2006

Progress Energy Florida, Inc., Crystal River Unit 4 and Unit 5, Letter of Intent dated November 2, 2006, Amendment 2, February 23, 2007

Progress Energy Florida, Inc., Crystal River Unit 4 and Unit 5, Letter of Intent dated November 2, 2006, Amendment 3, March 29, 2007

Progress Energy Florida, Inc., Crystal River Unit 4 and Unit 5, Letter of Intent dated November 2, 2006, Amendment 4, April 23, 2007

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DOCKET NO. 070007-EI EXHIBIT 23
COMPANY Progress Energy Florida
WITNESS Thomas Cornell (TC-3)
DATE 11-06-07

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 24
COMPANY Progress Energy Florida
WITNESS Thomas Cornell (TC-4)
DATE 11-06-07

COMPOSITE EXHIBIT NO. __ (TC-4)

REDACTED IN FULL

The Babcock & Wilcox Company ("B&W")

Contract 242070 executed July 14, 2005

Contract 119440, Effective March 14, 2003

Contract 119440, Amendment No. 9, Effective February 27, 2006

Contract 119440, Work Authorization 14, Effective April 20, 2006

Contract 119440, Work Authorization 14, Amendment No. 1, Effective December 5, 2006

Contract 119440, Work Authorization 15, Effective May 1, 2006

Contract 119440, Work Authorization 15, Amendment No. 1, Effective November 8, 2006

Contract 119440, Work Authorization 15, Amendment No. 2, Effective January 1, 2007

Contract 119440, Work Authorization 15, Amendment No. 3, Effective April 11, 2007

Contract 119440, Work Authorization 16, Effective May 1, 2006

Contract 119440, Work Authorization 16, Amendment No. 1, Effective October 16, 2006

Contract 119440, Work Authorization 16, Amendment No. 2, Effective January 1, 2007

Contract 119440, Work Authorization 17, Effective May 1, 2006

Contract 119440, Work Authorization 17, Amendment No. 1, Effective October 16, 2006

Contract 119440, Work Authorization 17, Amendment No. 2, Effective January 1, 2007

Contract 119440, Work Authorization 19, Effective October 20, 2006

Contract 119440, Work Authorization 19, Amendment No. 1, Effective January 1, 2007

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 25
COMPANY Progress Energy Florida
WITNESS Thomas Cornell (TC-5)
DATE 11-06-07

COMPOSITE EXHIBIT NO. __ (TC-5)

REDACTED IN FULL

WorleyParsons Group, Inc.

Contract 114016, Amendment No. 7, Effective November 11, 2002

Contract 114016, Work Authorization No. 24, Effective July 10, 2006

Contract 114016, Work Authorization No. 24, Amendment No. 1, Effective November 30, 2006

Contract 114016, Work Authorization No. 24, Amendment No. 2, Effective January 23, 2007

Contract 114016, Work Authorization No. 25, Effective August 1, 2006

Contract 114016, Work Authorization No. 25, Amendment No. 1, Effective November 9, 2006

Contract 114016, Work Authorization No. 26, Effective August 1, 2006

Contract 114016, Work Authorization No. 29, Effective September 19, 2006

Contract 114016, Work Authorization No. 29, Amendment No. 1, Effective December 31, 2006

Contract 114016, Work Authorization No. 42, Effective February 14, 2007

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 26
COMPANY Progress Energy Florida
WITNESS Thomas Cornell (TC-6)
DATE 11-06-07

EXHIBIT NO. __ (TC-6)

REDACTED IN FULL

CONTRACT NO.
298908

Between

Progress Energy Florida, Inc.

and

The Stebbins Engineering
and Manufacturing Company

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 27
COMPANY Progress Energy Florida
WITNESS Thomas Cornell
DATE 11-06-07

EXHIBIT NO. __ (TC-7)

REDACTED IN FULL

Purchase Order Agreement

Between

Progress Energy Florida, Inc.

and

CERAM Environmental, Inc.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 28
COMPANY Progress Energy Florida
WITNESS Thomas Cornell (TC-8)
DATE 11-06-07

EXHIBIT NO. __ (TC-8)

REDACTED IN FULL

CONTRACT NO.
300611

Between

Progress Energy Florida, Inc.

and

Commonwealth Dynamics, Inc.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 29
COMPANY Progress Energy Florida
WITNESS Thomas Cornell (TC-9)
DATE 11-06-07

Progress Energy Florida
Docket No. 070007-EI
Environmental Cost Recovery Clause

Exhibit No. __ (TC-9)

Redacted in its entirety

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 30
COMPANY Progress Energy Florida
WITNESS Samuel Waters CSW-1
DATE 11-06-07

Docket No. 070007-EI
PROGRESS ENERGY FLORIDA
Witness: Samuel S. Waters
Exhibit No. __ (SSW-1)

REDACTED

Progress Energy Florida
Integrated Clean Air Compliance Plan

Submitted to the
Florida Public Service Commission

June 1, 2007



Progress Energy

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List of Acronyms & Abbreviations

BACT ..... Best Available Control Technology
BART ..... Best Available Retrofit Technology BOFA
CAIR ..... Clean Air Interstate Rule
CAMR ..... Clean Air Mercury Rule
CAVR ..... Clean Air Visibility Rule
CPVRR ..... cumulative present value revenue requirements
DEP ..... Florida Department of Environmental Protection
EPA ..... U.S. Environmental Protection Agency
ESP ..... electrostatic precipitator
FGD ..... flue gas desulfurization
FIP ..... Federal implementation plan
Gwh ..... gigawatt-hour
Hg ..... mercury
lbs/mmBtu ..... pounds per million Btu
LNB ..... low NOx burners
LOI ..... loss on ignition
MW ..... megawatt
MWh ..... megawatt-hour
NOx ..... nitrogen oxides
NSR ..... New Source Review
O&M ..... operation and maintenance
OFA ..... overfire air
PAC ..... powdered activated carbon
PEF ..... Progress Energy Florida, Inc.
PM ..... particulate matter
SCR ..... selective catalytic reduction
SIP ..... State Implementation Plan
SO_2 ..... sulfur dioxide
SO_3 ..... sulfur trioxide
SOFA ..... separated overfire air

Executive Summary

The Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Clean Air Visibility Rule (CAVR) programs pose major new challenges for Progress Energy Florida (PEF). The purpose of this report is to update the Florida Public Service Commission (FPSC) on the status of the new regulatory programs and PEF's implementation of its Integrated Clean Air Compliance Plan. In addition, this report presents the results of PEF's continued evaluation of alternative plans and an assessment of risks that may affect the costs and timing of PEF's implementation of the selected plan.

On March 31, 2006, PEF submitted a report and supporting testimony presenting its integrated plan for complying with the new rules, as well as the process PEF utilized in evaluating alternative plans. PEF's Integrated Clean Air Compliance Plan, designated in the report as Plan D, was found to be the most cost-effective compliance plan for CAIR, CAMR, and CAVR from among five alternative plans. PEF determined that the Integrated Clean Air Compliance Plan meets PEF's objectives of (1) meeting all CAIR, CAMR, and CAVR requirements; (2) providing flexibility; (3) managing risk; and (4) controlling costs.

During the past year, changed conditions have necessitated revisions to the alternative plans evaluated in the 2006 report. The most significant changes, affecting four of the five plans, are the in-service dates of the Flue Gas Desulfurization (FGD) and Selective Catalytic Reduction (SCR) controls on Crystal River Unit 4. [redacted]. In addition, PEF has developed and evaluated a sixth alternative plan, designated Plan F. 1 2 3

Consistent with the approach utilized in 2006, PEF has performed a quantitative evaluation to compare the ability of the modified alternative plans to meet environmental requirements, while managing risks and controlling costs. The analysis included an examination of the projected emissions of the plans and economic impacts, in terms of cumulative present value of revenue requirements (CPVRR) of the six alternative plans. This analysis demonstrates that Plan D, as modified, still has the lowest CPVRR revenue requirements.

A summary of the primary components of this Plan are as follows:

SO_2

- Installation of wet scrubbers on Crystal River Units 4 and 5
- Fuel switching at Crystal River Units 1 and 2 to burn low sulfur coal
- Fuel switching at Anclote Units 1 and 2 to burn low sulfur oil
- Purchases of sulfur dioxide (SO_2) allowances

NOx

- Installation of low NOx burners (LNBs) and SCRs to control nitrogen oxide (NOx) emissions from Crystal River Units 4 and 5
- Installation of LNBs and Separated over-fire air (LNB/SOFA) at Anclote Units 1 & 2
- Purchase of annual and ozone season allowances

Mercury

- Installation of wet scrubbers and SCRs at Crystal River Units 4 and 5 will provide co-benefit of reducing mercury emissions
- Installation of powdered activated carbon injection on Crystal River Unit 2
- Purchase of mercury (Hg) allowances

The Plan is expected to meet environmental requirements by striking a balance between reducing emissions by adding controls to the largest and newest coal units on the PEF system, and making use of the allowance markets.

While a significant amount of study, engineering, and analysis has already been completed to support the development of PEF's Plan, there are still a number of uncertainties and outstanding issues. One of the primary outstanding issues relates to PEF's Anclote Units. Information provided by vendors indicates that while LNB/ SOFA installations are effective at reducing NOx emissions, they also have the potential to increase particulate emissions. PEF is engaged in a current study to determine the magnitude of potential increases, whether additional particulate controls – such as ESP's – would need to be added, what control technology to use and whether the cost of such additional controls would increase the cost per ton of NOx removal above the expected cost of NOx allowances. The full cost impact of this issue can not be determined at this time. For these reasons, this report also presents an assessment of risks that could impact the costs and timing of PEF's implementation of the Integrated Clean Air Compliance Plan. The Company will use this Plan to guide internal planning and budgeting efforts. However, since compliance planning is a dynamic process, PEF will continue to evaluate compliance options in light of changed circumstances and will adjust the Integrated Clean Air Compliance Plan accordingly.

Chapter 1 Overview of Report

Introduction

In March of 2006, PEF filed with the Florida Public Service Commission a report and supporting testimony outlining our integrated plan for complying with EPA's recently promulgated CAIR, CAMR, and CAVR programs. Among other things, the 2006 report described PEF's decision-making process and provided a clear understanding of why the Plan was chosen. The purpose of this report is to update the Commission on the status of PEF's implementation and continued evaluation of its Integrated Clean Air Compliance Plan.

Objectives and Decision Criteria

PEF's objective remains to select a plan that: (1) meets all CAIR, CAMR, and CAVR requirements; (2) manages risk; (3) provides flexibility; and (4) controls costs. These objectives require PEF to balance both cost and risk to select an "optimal" strategy. Each of these objectives can be further defined as follows:

- **Meet environmental requirements**—This objective is straightforward. PEF takes its environmental responsibility seriously and will meet all requirements of the CAIR, CAMR, and CAVR, and all other state and federal environmental regulations.
- **Manage risk**—In making long-term planning decisions, uncertainties are numerous and include the cost of technology options, fuel and allowance markets, and the structure and type of environmental regulations.
- **Provide flexibility**—Strategic flexibility is defined as the ability to change direction based on new information. As plans extend into the future, the possibilities for unforeseen circumstances increase. Therefore, it is important to maintain the ability to alter course based on new information.
- **Control costs**—PEF seeks to achieve compliance using the most cost-effective plan to provide emission reductions at the lowest reasonable cost to its customers.

Report Organization

The remainder of this report is organized as follows:

Chapter 2 provides a recap of the originally filed Integrated Clean Air Compliance Program.

Chapter 3 presents Findings and Recommendations based on PEF's continued evaluation of alternative compliance plans.

Chapter 4 summarizes the status of the pertinent regulations and PEF's implementation of its Integrated Clean Air Compliance Plan to date.

Chapter 5 discusses the analysis of the alternative plans and the results of the evaluations.

Chapter 6 provides an assessment of ongoing risks associated with PEF's compliance Plan.

Appendix 1 provides the summaries of contracts PEF has entered to date in implementing the compliance plan.

Chapter 2 Recap of Originally Filed Integrated Clean Air Compliance Plan

In March of 2006, PEF filed with the Florida Public Service Commission a report and supporting testimony outlining our integrated plan for complying with the U.S. Environmental Protection Agency's (EPA's) recently promulgated CAIR, CAMR, and CAVR programs. PEF's Integrated Clean Air Compliance Plan, which was designated in the report as Plan D, was found to be the most cost-effective compliance plan for CAIR, CAMR, and CAVR from among five alternative plans. The five plans considered a variety of compliance options including different types of control technologies, fuel switching, and allowance trading.

In the 2006 report, PEF projected capital costs of the plans to range from approximately $570 million to $1.2 billion, excluding AFUDC. AFUDC would increase the overall cost by approximately $62 million to $120 million. The Plan with the highest projected capital costs would have called for installation of scrubbers and SCRs on all four Crystal River units and NOx controls on both Anclote units to be in full compliance with both CAIR and BART. At the low capital cost end of the spectrum, PEF would have installed scrubbers and SCRs only on Crystal River Units 1 and 2 and NOx controls on the Anclote units at a capital cost of approximately $570 million to comply with CAVR and rely on fuel switching and allowance purchases for total CAIR compliance. The Plan that PEF indicated it intended to pursue (Plan D) included scrubbers and SCRs only on Crystal River Units 4 and 5, NOx controls on Anclote Units 1 and 2, allowance purchases, and fuel switching to comply with CAIR. The Plan relied on the premise that CAIR would satisfy BART requirements. Although the total capital costs for the Plan were projected at $736 million (excluding AFUDC), it had the lowest total projected costs when all factors were considered including allowance purchases, incremental O&M, and fuel switching. The majority of the capital costs would be incurred in the 2007-2009 time period.

A summary of the primary components of Plan D were as follows:

SO_2

- Installation of wet scrubbers on Crystal River Units 4 and 5
- Fuel switching at Crystal River Units 1 and 2 to burn low sulfur coal
- Fuel switching at Anclote Units 1 and 2 to burn low sulfur oil and natural gas
- Purchases of SO_2 allowances

NOx

- Installation of low NOx burners and selective catalytic reduction systems (SCRs) at Crystal River Units 4 and 5
- Installation of low NOx burners and separated over-fire air (LNB/SOFA) at Anclote Units 1 & 2
- Purchase of annual and ozone season allowances

Mercury

- Installation of wet scrubbers and SCRs at Crystal River Units 4 and 5 will provide co-benefit of reducing mercury emissions
- Installation of powdered activated carbon injection on Crystal River Unit 2

- Purchase of mercury (Hg) allowances

Quantitative Analysis of Alternative Compliance Plans

PEF performed a quantitative evaluation to compare the ability of the alternative plans to meet environmental requirements, while managing risks and controlling costs. The analysis included an examination of the projected emissions of the plans and economic impacts, in terms of CPVRR. As discussed in the 2006 report, Plan D had the lowest CPVRR. Plan A was projected to be the most expensive plan, largely due to the capital costs associated with the additional emission controls installed. Plans B and C, which also complied with CAIR without long-term purchases of allowances, were projected to be less costly than Plan A. It is noteworthy that Plan E was more costly than Plan D, even though the capital requirements were considerably less than any other plan. This was due to the significant amount of allowance purchases that would be required.

Qualitative Assessment of Plans

PEF also conducted a qualitative assessment of the plans in terms of providing flexibility as well as some potential uncertainties not considered in the quantitative assessment. As noted above, Plan D achieves compliance by installing emission controls on PEF's two largest coal units (as well as NOx controls on the Anclote units). Because Crystal River Units 4 and 5 are also the newest coal units on the system, there should be less uncertainty in the cost to install the equipment on the units. It also will be easier to install controls on Units 4 and 5 because there are fewer physical obstacles around which to design and construct the control equipment. Plan D also provides flexibility. Because SO_2 and NOx emissions were below or near the amount of allowance PEF was to receive through 2014 (or beyond in the case of SO_2), this provides time for resolution of allowance market uncertainties. If allowance prices and the projection of future allowance prices increase significantly, PEF would have the ability to add controls to Crystal River Units 1 and 2 at a later date. Plan D would also allow time for mercury control technologies to advance.

Selected Plan

PEF determined that Plan D was the preferable plan from a number of perspectives and it met all of the objectives set out by the Company. The Plan would strike a good balance between reducing emissions, by adding controls to the largest and newest coal units on the PEF system, and making use of the allowance markets to comply with CAIR. The plan would comply with CAMR by reducing mercury emissions through the synergistic effect of wet scrubber and SCRs on Crystal River Units 4 and 5. Emissions would be reduced greater than required in the early years, and these early reductions would be banked for use later in time. To reduce mercury emissions further and remain in compliance through 2025, activated carbon injection controls would be added to Crystal River Unit 2 prior to 2018.

Plan D provided flexibility by making use of allowance markets to account for a small portion of reductions required by CAIR. Because of the controls added for Plan D, PEF would need to purchase a minimal number of allowances through 2014. This would provide time for the allowance markets to stabilize, or for at least some of the market uncertainties to be resolved. Should it appear that allowance prices are going to be high after 2014, Plan D provided PEF with the ability to add controls to additional Crystal River units at a future date, possibly taking advantage of any technology improvements that may be made. Likewise, should PEF experience

higher load growth than expected, or if plans for future baseload units change, PEF could add controls on Crystal River Units 1 and 2, if necessary. Thus, Plan D enabled PEF to manage its risks better than the other plans developed.

Uncertainties

While a significant amount of study, engineering, and analysis had already been completed when PEF submitted the 2006 Plan, there were and still are a number of uncertainties and outstanding issues including opacity and particulate emissions, water use permitting, quality and sources of limestone, and effectiveness of mercury removal technologies. In addition to the project and technology uncertainties surrounding these projects, there remained a great deal of uncertainty associated with the regulations themselves and how the Florida DEP and US EPA would implement the rules. Due to these uncertainties, PEF indicated that it would continue to review its Plan and adjust it accordingly so as to assure compliance with all applicable regulations with the most cost effective strategy.

Chapter 3 Findings & Recommendations

During the past year, changed conditions have necessitated revisions to the alternative plans evaluated in the 2006 report. As discussed in Chapter 5, the most significant changes, affecting four of the five plans, are the in-service dates of the FGD and SCR controls on Crystal River Unit 4. [redacted]. In addition, PEF developed and evaluated a sixth alternative plan, designated Plan F.

Consistent with the approach utilized in the 2006 evaluation, PEF evaluated the six alternative plans to determine which would ensure compliance with the regulations and best meet the objections and decision criteria summarized in Chapter 1. This chapter describes the updated evaluation and the components of PEF's updated Integrated Clean Air Compliance Plan.

Integrated Clean Air Compliance Plan

PEF's Integrated Clean Air Compliance Plan, designated in this report as Plan D, has again found to be the most cost-effective compliance plan for CAIR, CAMR, and CAVR from among the six alternative plans. The Integrated Clean Air Compliance Plan still meets PEF's objectives of (1) meeting all CAIR, CAMR, and CAVR requirements; (2) providing flexibility; (3) managing risk; and (4) controlling costs.

The Plan meets environmental requirements by striking a good balance between reducing emissions, through installation of controls on PEF's largest and newest coal units, and making use of the allowance markets to comply with CAIR and CAMR requirements. It also provides flexibility by making use of allowance markets to account for a small portion of the reductions required by CAIR. Should it appear that allowance prices are going to be higher than currently projected, the Plan provides PEF with the ability to add controls to additional Crystal River units at a future date, possibly taking advantage of any technology improvements that may be made. The Plan also allows time for mercury control technologies to advance. Finally, should PEF experience higher load growth than expected, or if plans for future baseload units change, PEF may then add controls on Crystal River Units 1 and 2, if necessary. Thus, the Integrated Clean Air Compliance Plan enables PEF to manage its risks.

SO_2 Plan

The most significant component of PEF's Integrated Clean Air Compliance Plan is the installation of wet scrubbers on Crystal River Units 4 and 5. The plan includes switching Crystal River Units 1 and 2 to burn low-sulfur (1.2 lbs SO_2/mmBtu) "compliance" coal beginning in 2010, and burning low sulfur oil at Anclote Units 1 and 2 starting in 2010. [redacted]. PEF has assumed fuel switching to take place in the analyses described in this report. However, the final decision to switch fuels will be made closer to implementation time. The fuel to be burned by PEF at these units will be that which has the lowest overall cost when the cost of allowances is factored into the overall cost.

NOx Plan

The primary component of PEF's Integrated Clean Air Compliance Plan is the installation of LNBs and SCR systems on Crystal River Units 4 and 5. Currently, the Plan also includes LNB/SOFA controls to be installed on the Anclote units for NOx reductions. However, as discussed in Chapter 4, additional study of this option is required. These control options are among the lowest incremental cost options available, and provide most, but not all, of the NOx reductions required by CAIR. [redacted].

Mercury Plan

Installation of wet scrubbers and SCRs on Crystal River Units 4 and 5 will provide a co-benefit of reducing emissions of mercury. PEF expects mercury emissions reductions to be greater than required between 2010 and 2011, and the Integrated Clean Air Compliance Plan relies on being able to bank the excess reductions for use in later years. [redacted]. The Plan includes installing PAC injection systems with additional polishing filters on Crystal River Unit 2 [redacted] to further reduce mercury emissions. The polishing filters will provide PEF the ability to continue selling the fly ash produced rather than disposing of the ash in a landfill, thereby avoiding additional landfill costs. [redacted], PEF will continue to monitor the research and development of mercury control technologies and will choose the most reliable and cost-effective control technology when the time arrives.

Visibility Plan

PEF operates four units that are BART-eligible, including Anclote Units 1 and 2 and Crystal River Units 1 and 2 (Bartow Unit 3 is also BART-eligible, but is being repowered and is not included in the discussion here). As indicated above, the Integrated Clean Air Compliance Plan includes switching to low-sulfur oil and the installation of LNBs at Anclote Units 1 and 2, which will bring the Anclote units into compliance with CAIR. Per the Florida DEP's BART requirements, Rule 62-296.340, F.A.C., a BART determination is not required for SO_2 and NOx for any BART-eligible source that is subject to CAIR. Therefore, visibility impacts from particulate matter emissions are only evaluated for the BART determination. While additional controls may be required for individual units that are shown through modeling to contribute significantly to visibility impairment in a Class I area, PEF expects that installing controls on the larger Crystal River Units 4 and 5 will significantly improve the visibility in Class I areas, more so than would controlling emissions on Units 1 and 2 at Crystal River.

Chapter 4 Status of Regulations and Implementation of PEF's Integrated Clean Air Compliance Plan

This chapter provides an update of the status of the CAIR, CAMR and CAVR programs, as well as PEF's implementation of its Integrated Clean Air Compliance Plan.

Requirements Under the Clean Air Interstate Rule

This section discusses the regulatory requirements of CAIR, which EPA signed in March 2005.

General Overview

CAIR requires significant reductions of SO_2 and NOx from power plants in 28 eastern states and the District of Columbia through an emissions cap-and-trade program. CAIR will be implemented in two phases – the first phase beginning in 2010 for SO_2 and 2009 for NOx compliance, and the second phase beginning in 2015. When fully implemented in 2015, CAIR is expected to result in a 70 percent reduction in SO_2 emissions and a 65 percent reduction in NOx in the affected 28-state region as compared to current emission levels.

Status of CAIR Regulations

CAIR requires affected states to revise their SIPs to ensure achievement of specific emission targets. EPA encourages states to use a model cap-and-trade program included in CAIR, but states have the discretion to adopt alternative control programs to achieve CAIR emission targets. States were required to submit their SIP revisions to EPA by September 11, 2006. On June 29, 2006 the Florida DEP adopted a state CAIR that is based on the EPA model rule with minor revisions to the NOx emissions allocation period and the definition of new sources. An administrative challenge of the Florida CAIR delayed the state's submittal of the CAIR SIP revision. On March 1, 2007, however, an Administrative Law Judge upheld the Florida CAIR and, on March 16, 2007, the Florida DEP officially submitted its CAIR SIP revision for EPA review and approval. Under a Federal Implementation Plan (FIP) signed by EPA on March 15, 2006, the federal SO_2 and NOx cap-and-trade programs could be imposed if EPA does not officially approve Florida's SIP revision.

A group of Florida utilities, including PEF, has challenged EPA's decision to include the state of Florida in the federal CAIR. The legal proceedings will likely not conclude prior to 2008 and the outcome cannot be predicted.

Sulfur Dioxide Requirements

CAIR requires significant reductions in SO_2 emissions in the affected 28-state region. The reductions will be implemented in two phases – the first phase beginning in 2010 and the second phase beginning in 2015. CAIR encourages states to use the cap-and-trade approach that was established in Title IV of the 1990 Clean Air Act Amendments, which is also known as the Acid Rain Program. Under Title IV, SO_2 emissions allowances were allocated to all affected units. CAIR implements the additional reductions by increasing the number of allowances required to offset SO_2 emissions. Beginning in 2010, CAIR requires two allowances for each ton of SO_2 emitted, as compared to the one allowance per ton requirement under the existing Title IV program. Beginning in 2015, each ton of emissions will require 2.86 allowances.

Nitrogen Oxides Requirements

CAIR also requires significant reductions in NOx emissions in the affected 28-state region. The reductions will be implemented in two phases – the first phase beginning in 2009 and the second phase beginning in 2015. As with SO_2, CAIR encourages use of a cap-and-trade approach to achieve emissions reductions. Under the EPA model cap-and-trade program, EPA will allocate emissions allowances to each participating state. For instance, Florida will be allocated 99,445 allowances from 2009-2014, and 82,871 allowances in 2015 and thereafter. The states will then allocate their budgeted allowances to individual emitting units. Allocations will be made separately for both the annual and "ozone season" (May through September) periods.

PEF's anticipated total NOx allocations have changed since PEF originally submitted its Integrated Clean Air Compliance Plan in 2006. Expected annual allowances have decreased approximately 2,800 tons per year between 2009 and 2014, and 2,200 tons per year afterward. Ozone season allowances have decreased approximately 1,300 tons per year between 2009 and 2014, and 1,100 tons per year afterward. The CAIR methodology allocates allowances to specific units based on published heat input data, with downward adjustments to be made in the future based on the number of new units that become subject to the program. PEF continues to develop and implement its CAIR NOx compliance plan based on the emission targets and allocation methodologies set forth in Florida's adopted CAIR rule and pending SIP revision.

Permit Requirements

Each affected facility's Title V air operating permit will be revised to reflect changes required by the final state CAIR. In addition, air construction permits must be obtained prior to the installation of pollution control equipment.

Requirements Under the Clean Air Mercury Rule

This section provides a discussion of the regulatory requirements of CAMR, which was signed by EPA in March 2005.

General Overview

The final CAMR was signed by the Acting EPA administrator on March 15, 2005. CAMR requires significant reductions in mercury emissions nation-wide from coal-fired power plants through an emissions cap-and-trade program. CAMR will be implemented in two phases: the first phase beginning in 2010 and the second phase beginning in 2018. When fully implemented in 2018, CAMR will result in a 70 percent reduction in mercury emissions from coal-fired power plants in the U.S. Under CAMR, EPA will allocate mercury emissions allowances to each state that participates in the cap-and-trade program. The participating states will then allocate them to individual coal-fired units.

Status of CAMR Regulation

States were required to submit to EPA revisions to their SIPs by November 17, 2006. On June 29, 2006 the Florida DEP adopted a cap-and-trade rule based on the EPA model rule with adjustments to the number of allowances allocated during the first phase of implementation after 2011. Beginning in 2012, the rule allocates 70% of the available allowances to existing units, and it establishes a 25% set-aside. The set-side allowances may be used for compliance if a unit

has mercury pollution controls installed and still cannot meet its compliance obligation using the 70% allocation alone. The 25% set-aside results in a decrease of approximately 150 pounds in the total mercury emissions allocations to PEF's Crystal River coal-fired units between 2012 and 2017, compared to what PEF anticipated in its Integrated Clean Air Compliance Plan in 2006. The DEP submitted the adopted mercury rule to EPA as a SIP revision in December 2006.

Permit Requirements

Each affected facility's Title V air operating permit will be revised to reflect changes required by the final state mercury rule. In addition, air construction permits must be obtained prior to the installation of pollution control equipment.

Requirements Under the Clean Air Visibility Rule

This section provides a discussion of the regulatory requirements of the Clean Air Visibility Rule (CAVR), which was signed by EPA in June 2005.

General Overview

On June 15, 2005, EPA finalized amendments to the 1999 regional haze rule. Among other things, the final version of CAVR requires best available retrofit technology (BART) controls for certain industrial facilities emitting air pollutants that reduce visibility in certain areas. These areas are designated as Class I, and they include national parks and wilderness areas. There are four such areas in Florida, including Everglades National Park, Chassahowitzka National Wildlife Refuge and the St. Marks and Bradwell Bay Wilderness Areas.

Status of CAVR Regulation

States are in the process of adopting the federal CAVR requirements. States must submit to EPA their SIPs revisions by December 17, 2007. The Florida DEP adopted a CAVR based on the federal rule in January 2007.

BART Requirements

BART requirements apply to facilities that began operation between August 1962 and August 1977. These BART-eligible sources may be required to install BART for SO_2, NOx and particulate matter, if they are not subject to CAIR and do not adversely impact visibility of near by Class I areas. PEF operates five BART-eligible sources, including Anclote Units 1 and 2, Bartow Unit 3, and Crystal River Units 1 and 2.

The EPA rule establishes presumptive BART emission limits for coal-fired and oil-fired units greater than 200MW in size. For SO_2, the presumptive limit for coal units is based on use of flue gas desulfurization (FGD or "scrubbers") with a 95 percent removal efficiency or an emissions rate of 0.15 lb SO_2/mmBtu. For oil-fired units such as the Anclote units, the presumptive limit for SO_2 is oil with a sulfur content of less than one percent. For NOx, the EPA presumptive limit for tangential coal-fired boilers such as Crystal River Units 1 and 2 is 0.28 lb NOx/mmBtu. BART for NOx emissions from an oil-fired unit is defined as combustion controls. Particulate matter from coal-fired units is already controlled with electrostatic precipitators (ESPs), and the BART regulation is silent on particulate control for oil-fired units.

The deadline for installing BART controls in the Florida rule is December 31, 2013. Per the Florida DEP's BART requirements, a BART determination is not required for SO_2 and NOx for

any BART-eligible source that is subject to CAIR. If after the December 2013 compliance deadline, Florida DEP determines that reasonable progress has not been made toward improving visibility in Class I areas, controls may be required for individual units. This additional further progress requirement may impact Crystal River Units 1 and 2, which would lead to the installation of additional controls prior to December 31, 2017.

Permit Requirements

The Florida BART rule required that utilities submit BART permit applications for affected units by January 31, 2007. These applications were required to contain demonstrations that the CAVR BART requirements will be satisfied or notify that the units are exempted from the rule. Changes resulting from BART implementation will be reflected in amendments to the facilities' Title V air operating permits. In addition, air construction permits must be obtained prior to the installation of pollution control equipment. PEF timely submitted its BART notifications/applications, and they are currently under review by the DEP.

The Crystal River Units 1 and 2 BART application addressed particulate matter emissions. Particulate emissions were modeled at the New Source Performance Standard level of 0.015 pounds per million BTUs heat input. The modeling showed no appreciable change in visibility at the Class I areas; therefore, PEF concluded that no additional particulate controls are required. On February 27, 2007 the FDEP requested additional information regarding PEF's application. PEF is currently in the process of responding to this request.

For Anclote Units 1 and 2, PEF has provided all additional information requested by the Agency and is awaiting FDEP's determination of the BART exemption.

Other Environmental Requirements

NPDES Permitting

SCR and FGD systems create wastewater that must be treated and discharged to the environment. A discharge of waste water to surface waters is not anticipated. The existing National Pollutant Discharge Elimination System (NPDES) permits for the affected generating units will not need to be modified to authorize the discharge of treated wastewater.

Consumptive Use (Water) Permitting

FGD systems require the use of a large amount of freshwater, brackishwater and /or seawater in the pollutant removal process. Freshwater and/or brackishwater would be withdrawn from the existing underlying aquifer. Saltwater would most likely be withdrawn from an existing plant intake. The Southwest Florida Water Management District (SWFWMD or District) is the permitting authority for the consumptive use of water at the Crystal River site. Freshwater is a limited and valuable resource that is becoming more difficult to obtain. To procure an authorization for the freshwater withdrawal, an extensive demonstration of need and impact must be made to the District. The District will require that efforts be made to reduce the use of freshwater to the maximum extent possible. This would include the minimization of the existing water use as well as any possible process changes that could result in water conservation. The District also requires consideration of the lowest quality of water that is acceptable. Lower quality saltwater or brackishwater can be used in some FGD systems and, therefore, will need to be addressed as a potential alternative to freshwater during the consumptive use permitting

process. The SWFWMD has requested that PEF perform a water supply alternatives analysis investigating the potential to utilize saltwater, brackish water and/or desalinated water in place of fresh groundwater wherever feasible. This study must be completed prior to any staff recommendation to the District Governing Board. District staff has stated that no water will be authorized for use in Units 1 & 2 at this time.

NSR Permitting

Under DEP's New Source Review (NSR) permitting program, preconstruction air permits are required for plant modifications that result in significant increases in certain air pollutants. One condition of NSR permitting is to install Best Available Control Technology (BACT) for emission increases above specific threshold levels. Historically, pollution control projects were exempt from NSR permitting. In 2005, however, a federal appeals court vacated the NSR exemption for pollution control projects and, effective February 2006, the exemption was removed from Florida's SIP. As a result, NOx or SO_2 control projects included in PEF's compliance plan are now be subject to NSR review if they result in significant increases in other pollutants, such as particulate matter.

On May 18, 2007, the DEP issued a final air construction permit for the Crystal River Unit 4 and 5 projects. Among other things, the permit included BACT requirements for particulate matter (PM/PM_{10}), sulfuric acid mist, and carbon monoxide. The estimated cost of these requirements has been included in the economic analysis presented in Chapter 5. However, there is an outstanding issue regarding the potential effect of the Anclote LNB/SOFA projects on particulate emissions. PEF is analyzing whether the LNB/SOFA projects will result in increases of particulate emissions that trigger BACT requirements. If BACT is required, additional particulate controls, such as precipitators, would likely need to be installed and, as a result, the project schedules would need to be moved back in time. If it is determined that precipitators or other controls need to be installed, PEF will evaluate whether the cost of the additional controls increases the cost per ton of NOx removal above the expected cost of NOx allowances. Because PEF's analysis of the issue is ongoing, however, cost estimates for particulate controls and potential schedule impacts have not been incorporated into PEF's economic analysis.

Status of PEF's Integrated Clean Air Compliance Plan

This section provides an update of PEF's implementation of its Integrated Clean Air Compliance Program.

Significant Milestones

PEF is currently working with Environmental Partners Crystal River (EPCR), a joint venture of the primary engineering and construction companies, to finalize the Engineering, Procurement and Construction (EPC) contract and to complete the detailed construction schedule for Crystal River Units 4 and 5 work. In order to ensure the in-service dates are met for the key environmental equipment installation for Crystal River Units 4 and 5, the following schedule of key milestone activities have been agreed upon between PEF and EPCR.

Date	Activity
May 2007	Mobilize contractors & begin site preparation
Third Quarter 2007	Complete foundation work
Third Quarter 2008	Absorber tower erection complete
[redacted]	[redacted]
Fourth Quarter 2008	Crystal River Unit 5 liner and duct complete
First Quarter 2009	Material handling construction complete
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

1
2
3
4
5

Project to date Spending

As of the end of the first quarter 2007, the approximate total project costs incurred by Progress Energy Florida (PEF) for expenditures related to CAIR are $58 million. The $58 million includes: $55 million of contract billings, $2 million of owners costs, and $1 million of AFUDC. AFUDC began accruing with the start of construction in March 2006. The contract billings include payments for: design and engineering work, procurement of major equipment, issuance of a Letter Of Intent (LOI) and environmental permits.

Design and engineering work is being performed by two major vendors, Worley Parsons and Babcock & Wilcox. The major equipment that is being procured includes: ID fans, limestone silos, rotary feeders, piping, oxidation air blowers, SCR expansion joints, chimney, catalyst, and stack/absorber.

Pursuant to the LOI, [redacted] was paid to the construction vendor; Environmental Partners Crystal River (EPCR). EPCR consists of three vendors: Zachry, Burns & McDonnell, and Utility Engineering. EPCR is currently mobilizing and has initiated site and prep-work for upcoming construction.

Permits for SCR air, storm water modification, waste water, and VBS exemption have been approved through April 2007. Other permits that have been applied for include an air construction permit, a consumptive water use permit, access road environmental resources permit (ERP), and a permit for the well water pipeline.

Chapter 5 Evaluation and Results

This section provides a quantitative analysis of the alternative compliance plans, including an examination of the projected emissions of the plans and the impact on costs, in terms of cumulative present value of revenue requirements (CPVRR).

Plans Evaluated

The alternative compliance plans evaluated for this report are similar to the plans evaluated in PEF's 2006 report, with some minor changes, as discussed below. No other changes were made to the plans. Implicit in this is the assumption that all the plans can be implemented today as envisioned, which is not likely the case. For all practical purposes, Plans A and E cannot be implemented as originally indicated, simply due to the passage of time. Even though they cannot be implemented, they are still shown in the analysis results to maintain continuity with the 2006 Plan report.

Changes to Alternative Plans

During the past year, changed conditions have necessitated revisions to the alternative plans. The most significant changes, affecting four of the five plans, are the in-service dates of the FGD and SCR controls on Crystal River Unit 4. [redacted].

PEF changed the Unit 4 FGD and SCR project schedules to (1) optimize the most efficient construction schedule, which will mitigate cost escalation risks, (2) account for constrained labor and equipment availability in the 2008-2009 time frame. The original schedule called for as much work as possible to be done on Crystal River Unit 4, including installation of the SCR, during an outage planned for the [redacted] so that the work necessary for the tie in of the FGD in [redacted], would be minimal. This was necessary to avoid impacting an outage already planned for the [redacted] on PEF's Crystal River Unit 3. Due at least in part to the increased demand for pollution control projects prompted by the adoption of CAIR, lead-times for critical SCR equipment have increased. To compensate for the increased lead-times, in late 2006, the company decided to reschedule the Unit 4 SCR project for an outage in the [redacted]. As preliminary engineering and planning progressed, however, it became evident that there was not adequate time to permit, design, engineer, procure, and construct the Unit 4 SCR system by the [redacted]. We considered various options and chose to combine the SCR and FGD work into one outage in the [redacted]. Given the scope and amount of work to be performed at the Crystal River Energy Complex in the [redacted] outage, we determined that it would not be reasonable or prudent to combine the Crystal River Unit 4 SCR and FGD project into that outage.

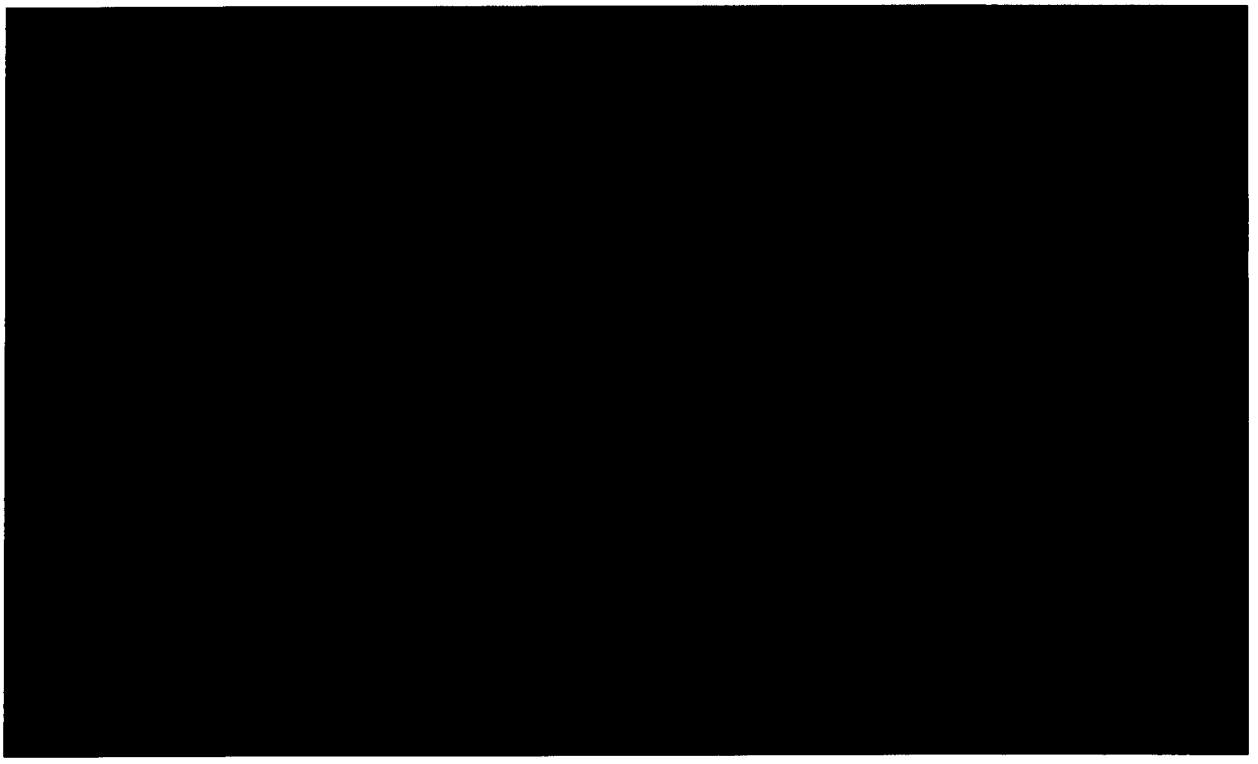
The other change, which affects Plans D and E, is the elimination of the use of natural gas at the Anclote Plant. In the 2006 report, the Anclote Plant was assumed to burn 40% natural gas after 2010 in Plans D and E. Burning 40% natural gas was determined to be economical for SO_2 emissions reduction; however, the analysis assumed that the pipeline capacity to get natural gas to Anclote was available at no additional cost. This assumption is no longer valid as there is no extra pipeline capacity available. Including a pipeline reservation fee makes burning gas at

Anclote uneconomical at this time. An alternative to reserving new pipeline transportation would be to divert natural gas for Anclote from the PEF combustion turbines (CTs) and burn distillate (#2) fuel oil at the CTs; however, doing so would increase emissions and increase costs since distillate fuel oil is more expensive than natural gas and the residual (#6) fuel oil used at Anclote. As discussed in the 2006 report, the final decision to switch to lower sulfur fuels will be made closer to implementation time. The fuel to be burned will be that which has the lowest overall cost. PEF will continue to monitor the fuel price and pipeline availability dynamics.

In addition to these five plans, a new alternative plan, Plan F, was developed and evaluated. Plan F is similar to Plan A, but the controls on Crystal River Units 1 and 2 are on a delayed schedule. In Plan F, FGD and SCR controls are added to Crystal River Unit 1 by 2015 and FGD and SCR controls are added to Crystal River Unit 2 by 2016. Once controls are added, Plan F is the same as Plan A from an emissions perspective. Plan F also represents how Plan D could evolve if circumstances change in the future. The additional controls on Units 1 and 2 may need to be added in response to the "Beyond BART" requirements of the Clean Air Visibility Rule, as discussed in Chapter 4, or they could be added if allowances prices turn out to be higher than anticipated.

Table 1 outlines the six plans evaluated.

Table 1. Summary of Alternative Compliance Plans



Environmental Compliance

The compliance achieved by each plan for CAIR and CAMR is demonstrated by the following charts. In the charts, the projected emissions of SO_2, NOx, and mercury for Plans A through F are shown compared to the number of allowances the Company expects to receive. The expected allowances are shown by a black line. For SO_2, the line showing allowances actually represents "emission-equivalent" allowances. Emission-equivalent allowances are the number of allowances divided by the "CAIR factor." The CAIR factor is the number of allowances that must be "redeemed" for each ton of SO_2 emissions. The value of the CAIR factor is 2.0 from 2010-2014 and 2.86 in 2015 and beyond.

SO_2

The projected PEF system emissions of SO_2 for the Baseline (without CAIR) and for Plans A through F are shown in Figure 1. As can be seen in the chart, only Plan A reduces emissions below the number of allowances during Phase I of CAIR, and only Plans A and F have emissions below the number of allowances during Phase II. Plans A and F have scrubbers on all four Crystal River coal units. Plans B and C, which include scrubbers on three of the four Crystal River coal units, have emissions near the number of allowances in Phase II. [redacted]. The chart also shows that Plan D will reduce emissions by more than [redacted] compared to the Baseline.

Figure 1. SO_2 Emission Projections

[redacted]

NOx

The projected PEF system emissions of annual NOx for Plans A through F are shown in Figure 2 (ozone season emissions are approximately half of the annual allowances). As shown in the chart, none of the plans reduces emissions below the number of allowances in 2009 through 2011. Only Plan A reduces emissions below the number of allowances during the latter half of Phase I of CAIR, and only Plans A and F have emissions below or only slightly above the number of allowances after 2015. Plans A and F have SCRs on all four Crystal River coal units. [redacted]). The chart also shows that Plan D will reduce NOx emissions by more than [redacted] compared to the Baseline.

Figure 2. NOx Emission Projections

[redacted]

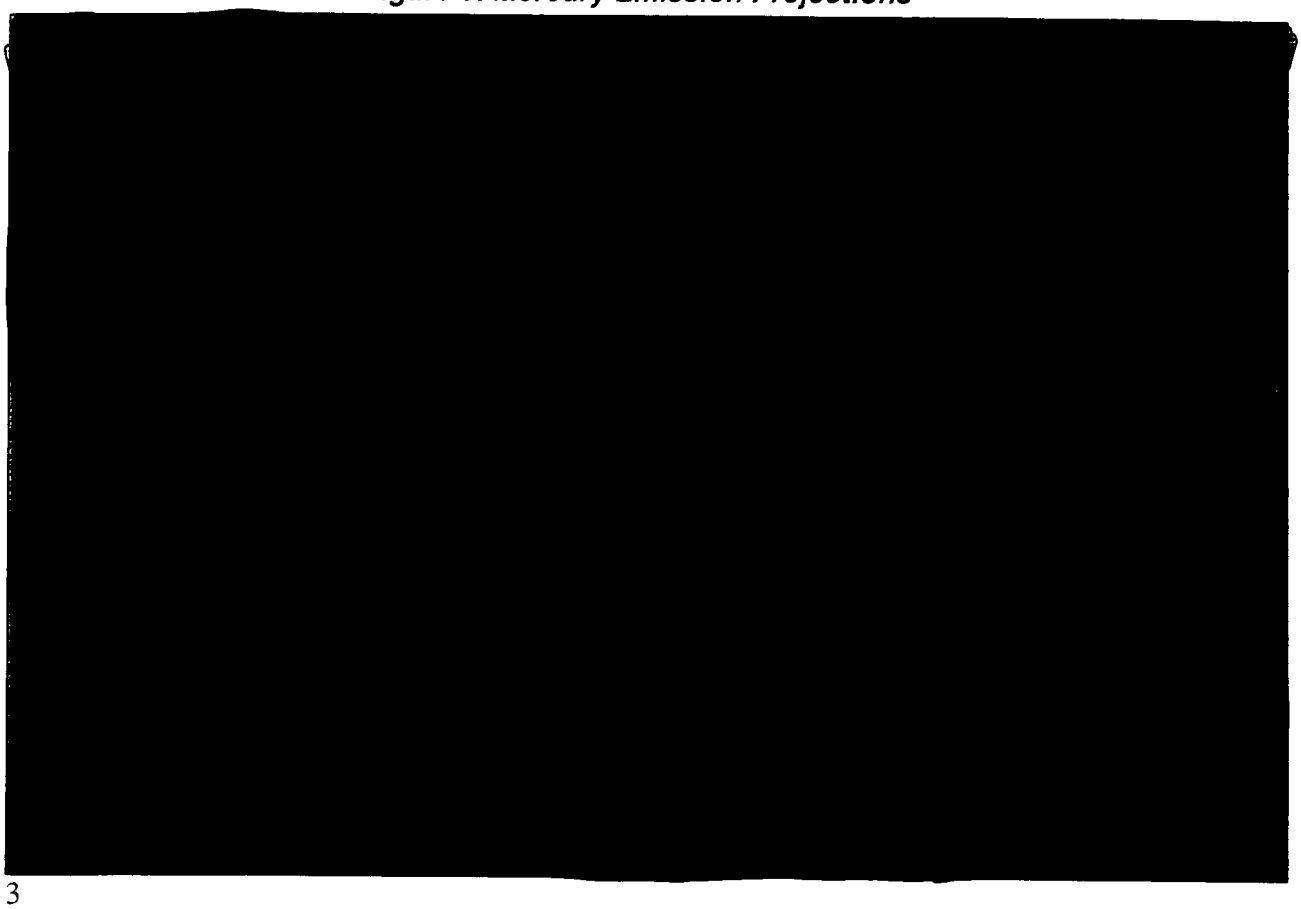
Mercury

The projected PEF system emissions of mercury for Plans A through F are shown in Figure 3. Only Plan A reduces mercury emissions below the number of allowances in all years of Phase I. Plans B, C, D, and F reduce emissions below the number of allowances in 2010 and 2011, and would be able to bank and use these allowances to cover emissions that are greater than the number of allowances during the latter years of Phase I. In Phase II, none of the plans reduce

emissions below the number of allowances provided; thus, either additional controls will be required or allowances will need to be purchased. [redacted]. The chart shows that the Plan D mercury emissions are reduced by over [redacted] compared to the Baseline.

The increase in mercury emissions during Phase II is due to new coal unit additions in the later years of the study. The proposed SIP includes a new unit set-aside provision, so additional allowances may be available, reducing the need for reductions as shown in the chart.

Figure 3. Mercury Emission Projections



3

Economic Impact of Compliance

As described above, the economic impact of the alternative compliance plans were compared using the CPVRR. Included in the CPVRR are the projected capital and O&M costs associated with controls, the projected cost of reagents (limestone and ammonia), credits for the sale of by-products (gypsum), the projected change in fuel costs compared to the Baseline projection, and the projected cost of purchasing or selling allowances.

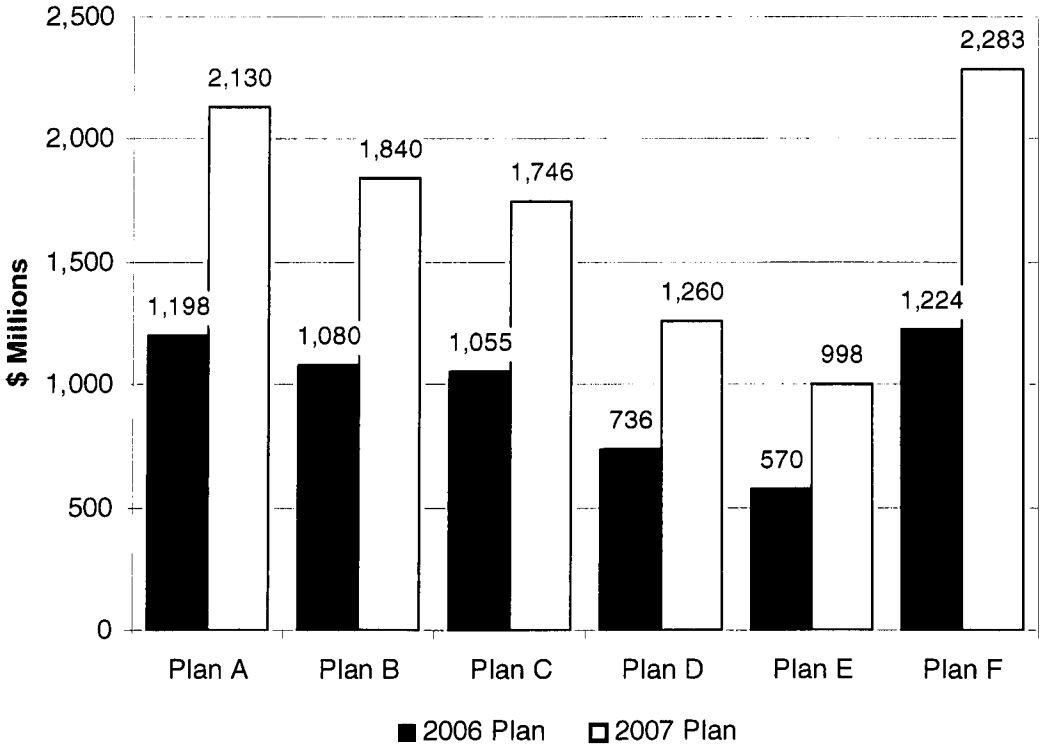
Changes in Assumptions

Construction Costs

The estimated costs to add pollution controls on the PEF units have increased since the time the 2006 Compliance Plan and are shown in Figure 4. The construction costs for Plan D are now approximately 70% greater than they were in the 2006 Plan Report. There are several reasons for the cost increases.

One of the impacts of the final CAIR rule was to create significant industry demand for major retrofit construction projects to engineer, procure, and install the necessary air pollution control equipment. This occurred at a time when there was already significant construction activity due, in part, to an improving economy. The situation was exacerbated by even more construction demand in the aftermath of Hurricane Katrina and by the rising demand for steel, concrete and other commodities in countries such as China and India. As a result of these world-wide market conditions, PEF and the industry began to see significant increases in costs for major construction projects, especially for SCR and scrubber installations. The increases were primarily driven by significant escalation in the cost of basic construction materials and in labor costs.

Figure 4. Construction Expenditures Compared to 2006 Plan

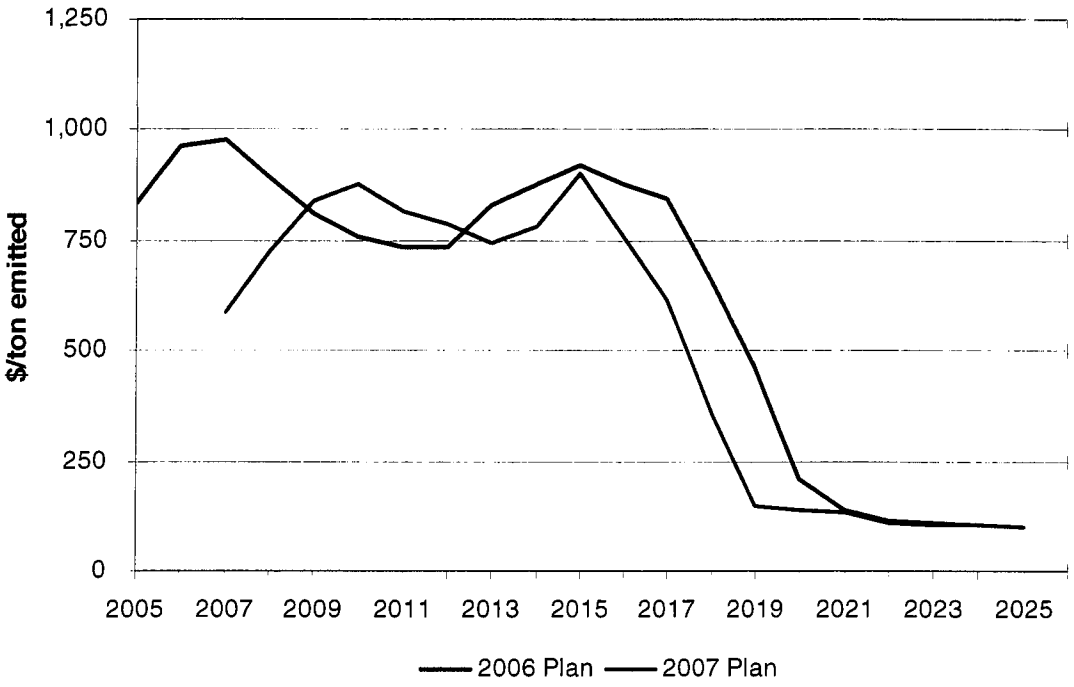


Allowance Prices

As discussed in the 2006 PEF Compliance Plan report, allowance prices have been extremely volatile. Since the time of the 2006 Plan, forecasted allowance prices have decreased according to the Company's allowance price forecast service, as shown in Figures 5 and 6. Also discussed

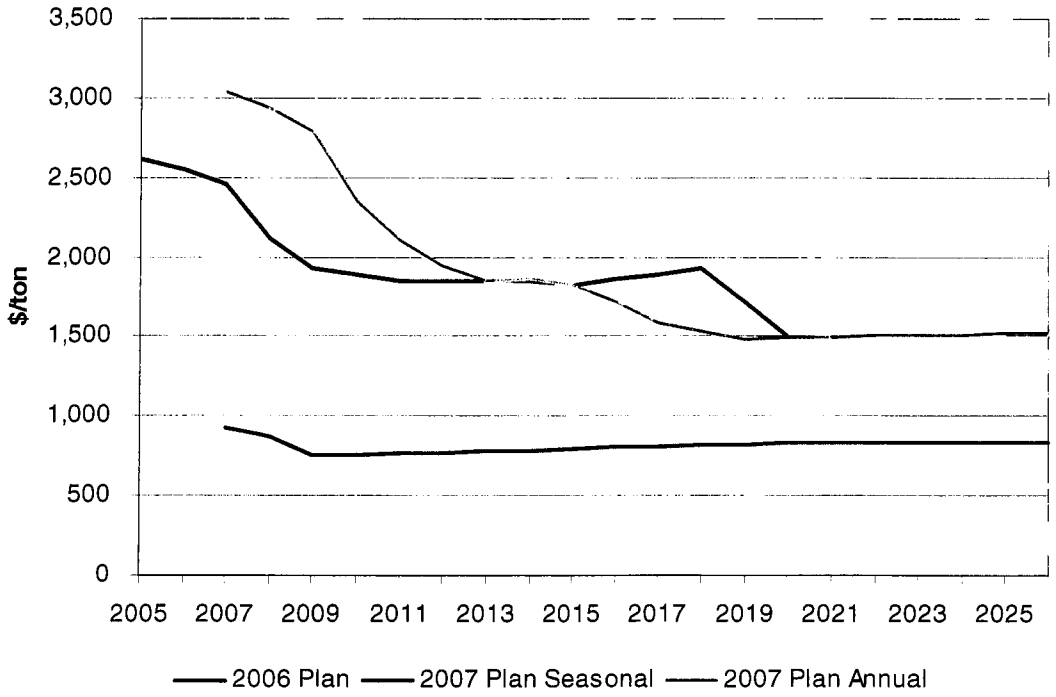
in the 2006 Plan was the uncertain nature of allowance prices. This uncertainty has not been resolved. Figures 7 and 8 show projected high and low SO_2 and NOx allowances prices.

Figure 5. Comparison of SO2 Allowance Price Forecasts



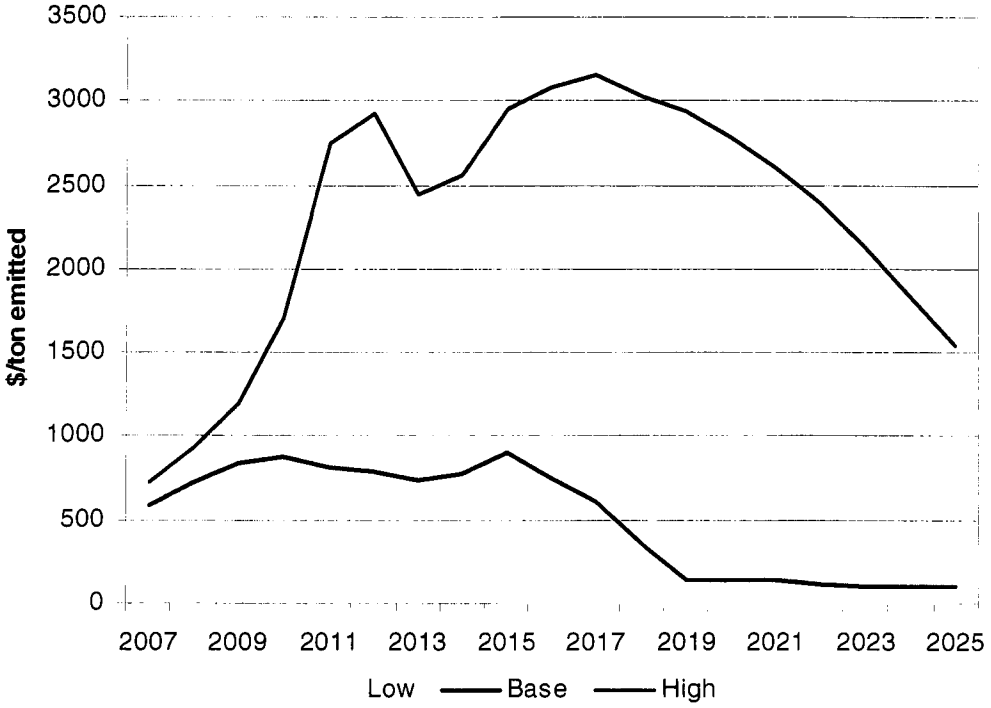
Source: JD Energy

Figure 6. Comparison of NOx Allowance Price Forecasts



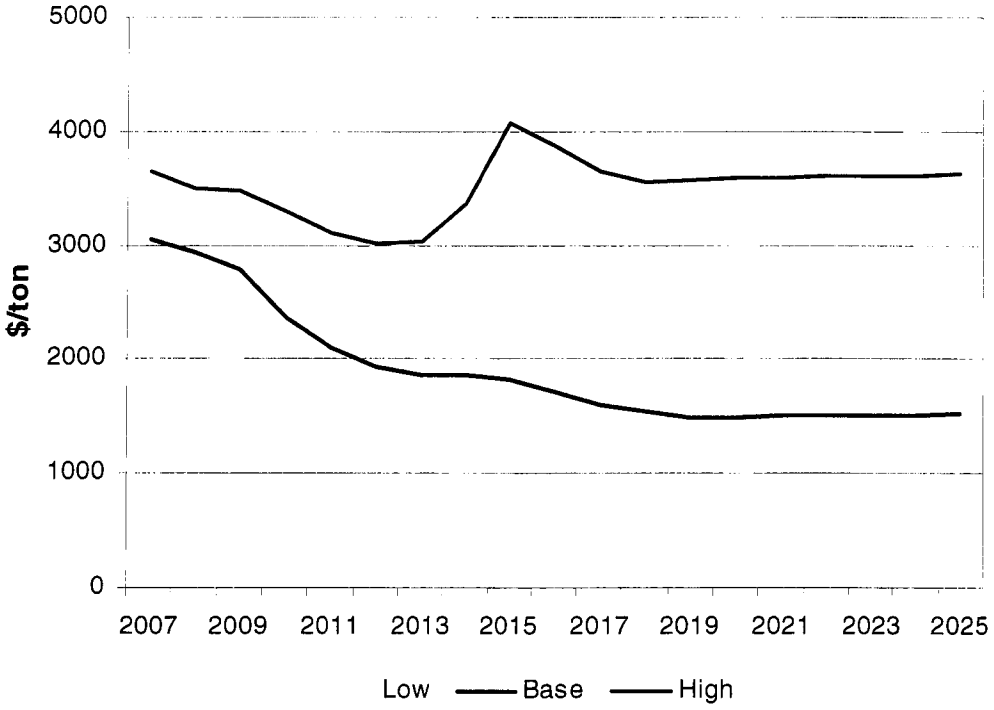
Source: JD Energy

Figure 7. Uncertainty in SO_2 Allowance Prices



Sources: JD Energy

Figure 8. Uncertainty in NOx Allowance Prices

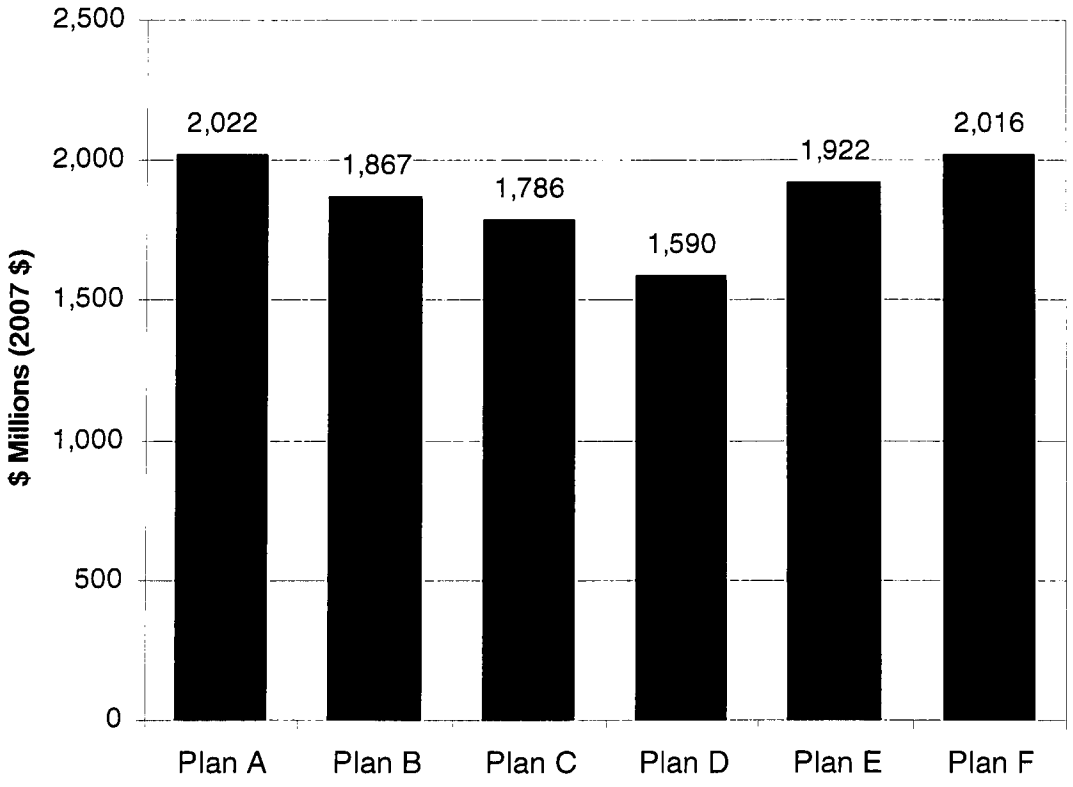


Source: JD Energy

Results of Economic Analysis

The higher capital costs associated with the pollution controls result in higher revenue requirements compared to the 2006 Plan. Because the cost for controls on each of the units increased, the costs of the plans relative to each other are consistent with what was seen in the 2006 Plan. The evaluated CPVRR of the plans are shown in Figure 9. The figure shows Plan A to be the most expensive plan and Plan D to be the least expensive plan. The results shown in Figure 9 are the costs including the economic impact of assuming allowances are either sold or purchased in each year (rather than banking allowances and using them in later years).

Figure 9. Comparison of Cumulative Present Value of Revenue Requirements

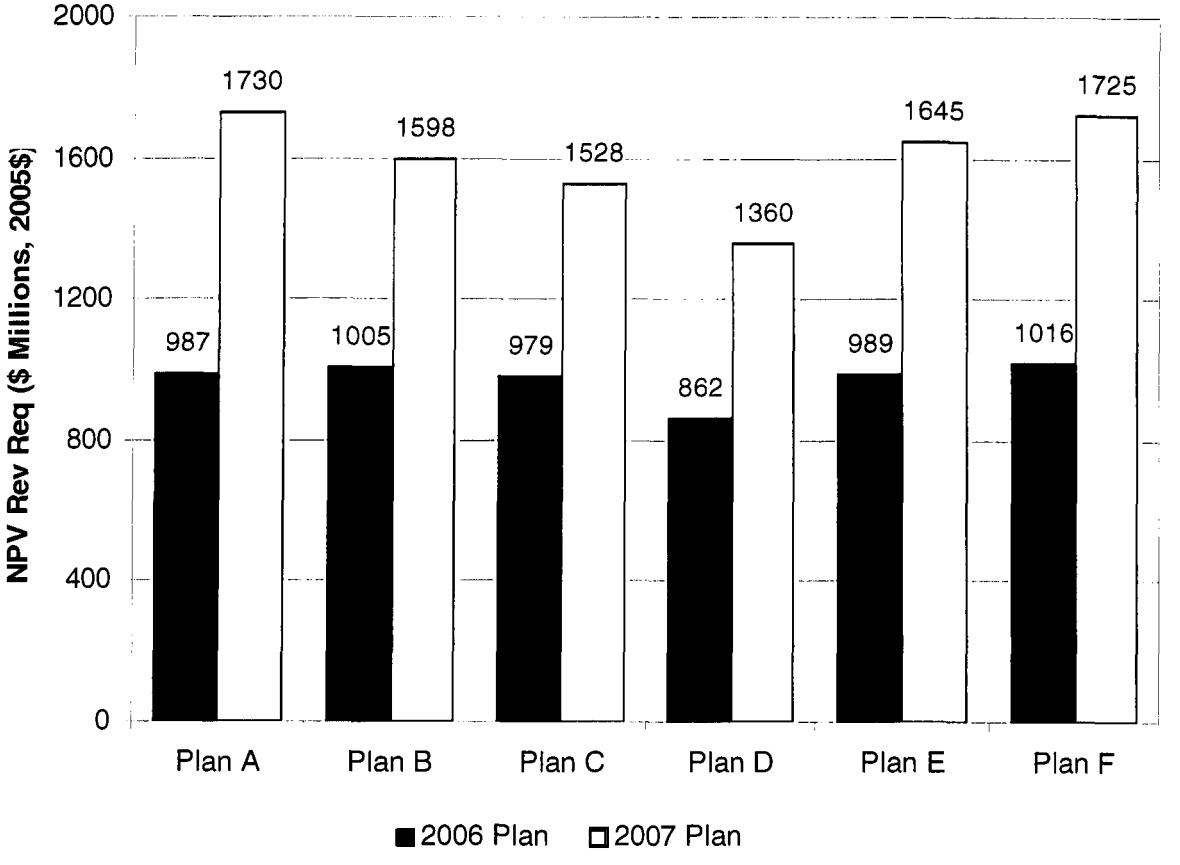


As in the 2006 Plan, the higher CPVRR cost of Plans A, B, C, and F are largely due to the capital costs associated with the emission controls installed. Plans B and C, which also comply with CAIR without significant long-term purchases of allowances, are less costly than Plans A and F. This result is expected because only three of the Crystal River units have emission controls installed, compared to Plans A and F, which have controls installed on all four units. Plan D is the plan with the lowest cumulative present value of revenue requirements. Plan D strikes a balance between installing controls and buying allowances by adding controls to the two largest coal units on the PEF system. It is noteworthy that Plan E is more costly than Plan D, even though the capital expenditures are considerably less. This is caused by the significant amount of allowance purchases that would be required with Crystal River Units 1 and 2 controlled, as assumed in Plan E, rather than Units 4 and 5 in all the other plans. The difference in costs between Plan D and Plan F illustrates the additional costs that may be incurred if pollution

controls are required on Crystal River Units 1 and 2 in order to comply with the "beyond BART" requirements of CAVR.

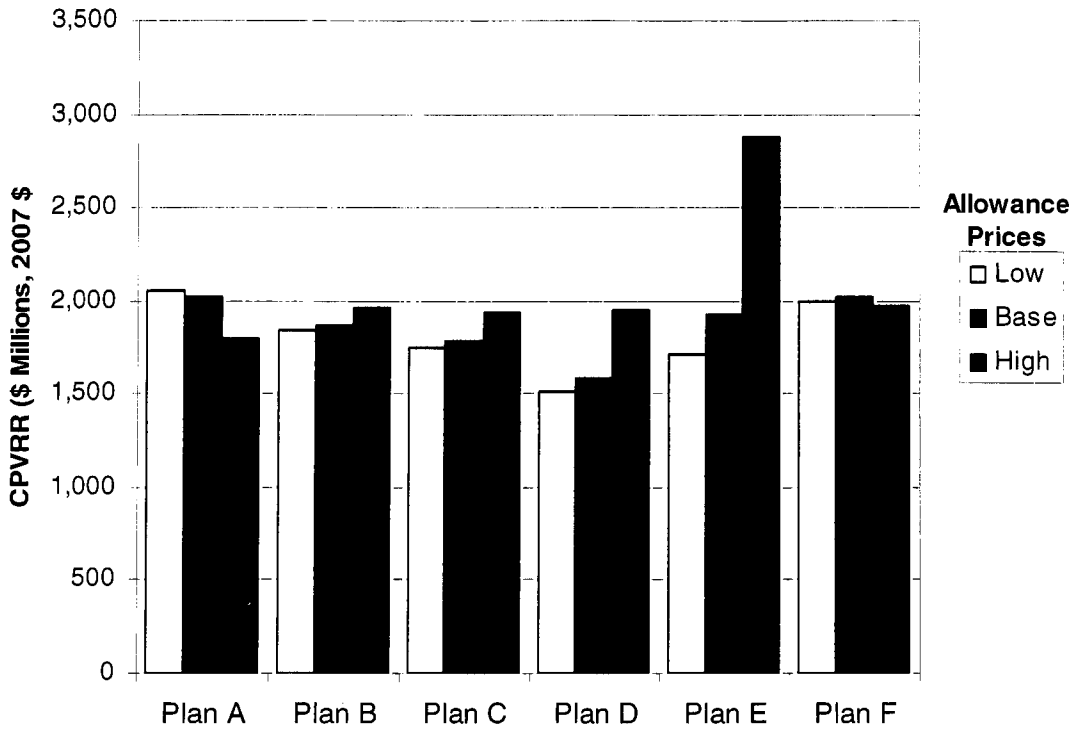
The CPVRR costs of the plans are now higher than what was projected in the 2006 Plan Report, as shown in Figure 10. The CPVRR cost of Plan D is now approximately 60% higher than the cost evaluation prepared for the 2006 Plan Report. As can be seen in the figure, the cost of the other plans increase by similar, or higher, percentages. Plans B, C, and E are between 55% and 65% higher than in the 2006 Plan Report and Plans A and F are 75% and 70% higher, respectively.

Figure 10. Costs of Plans Compared to 2006 Plan



Because the alternative plans developed rely on varying amounts of allowance purchases and the economics of some of the plans are impacted through the assumed sale of allowances more than others, the plans were also evaluated using the lower and higher allowance prices shown in Figures 7 and 8. Figure 11 presents the CPVRR of the alternative plans assuming low and high prices, in addition to the base allowance prices. The figure shows Plan D is the lowest cost plan under the base and low allowance price assumptions. Assuming high allowance prices, Plan A would be the most economic plan This is because Plan A has SO_2 and NOx emissions below the number of allowances received and can, therefore, sell allowances, reducing the overall cost of the plan. Plan E has the highest CPVRR when allowance prices are high because of the higher number of allowances that must be purchased to achieve compliance. Plans B, C, D, and F have approximately the same total CPVRR under the high allowance price scenario.

Figure 11. Impact of Allowance Price Uncertainty



Conclusion

As in the 2006 study, the economic analyses identify Plan D as the most cost effective alternative to meet the CAIR, CAMR, and CAVR regulations. Not only is Plan D the most cost effective plan under the base assumptions, it is the least cost plan if allowance prices are lower than the base assumptions and its costs are approximately the same as other plans that could be implemented if allowance prices go as high as tested under the high allowance price scenario. Thus, Plan D represents a good balance between adding controls and making use of allowance markets to comply with CAIR and CAMR requirements. If allowance prices appear to follow the high price forecast, Plan D provides PEF with the ability to add controls to either, or both, of Crystal River Units 1 and 2 in the future.

Chapter 6 Risk Assessment

As discussed in PEF's 2006 report, there are a number of uncertainties associated with the new CAIR, CAMR, and CAVR programs. These include regulatory uncertainties concerning the state's implementation of the new rules, as well as technological issues. This section provides an assessment of ongoing risks that could impact the costs and timing of PEF's implementation of its Integrated Clean Air Compliance Plan.

Environmental regulation

The compliance plan assumes no significant change in environmental laws and regulations during the course of this project. Potential changes in mercury and/or greenhouse gas legislation may impact the controls and/or technologies deployed.

Permits and Authorizations

The schedule assumes the timely receipt of approvals and permits from local, state, and federal regulatory agencies to facilitate the start of construction, including site certification, air permits, storm water, well water, access roads, wetlands mitigation, and wastewater. Other construction projects in Florida have experienced numerous permitting delays.

Third-party intervention

Certain segments of our existing workforce are unionized and the representative bargaining unit may intervene from time to time with the equipment and construction vendors selected for the project (mostly open shop contractors).

Allowance for Funds Used During Construction (AFUDC)

Currently the AFUDC rate applied to major construction projects has been established by the Florida Public Service Commission and our estimates assume average annual cash flows as the basis for AFUDC calculation. Changes in either the timing of cash flows on a monthly basis or changes in the AFUDC rate prescribed by the FPSC may alter the total project cost.

Scope Changes

Although we are seeking certain firm-price contracts for the major equipment and construction aspects of the project, any subsequent scope changes, unknown site conditions, or unknown degradation to existing plant equipment/systems may result in cost impacts to the project.

Pre-existing site conditions

Although certain engineering and design activities have been completed, unforeseen pre-existing site conditions (subsurface, excavation, hazardous materials, etc.) may not be known until construction begins. Additionally, inspections of the internal operations of plant equipment may result in additional design modifications or change orders.

Design scope definitions

The full design scope definitions may not be fully clarified at the time the EPC contract is signed. Such items shall be treated as an allowance and cost may increase or decrease based upon further engineering studies.

Schedule
Although most contracts contain provisions for date certainty completion with liquidated damages for delays, the non-performance of suppliers or contractors may adversely impact the schedule and/or cost of the project. The schedule assumes our ability to procure major long-lead time equipment and obtain permits on a timely basis. Additionally, as discussed below, force majeure events could adversely impact the construction schedule and cost of the project.

Change orders and/or claims
As common in the construction industry, certain aspects of the execution of the contract may need to be altered due to investigations, inspections or other unforeseen modifications in the design that may result in either change orders or claims and these modifications may alter cost and/or schedule assumptions.

Vendor solvency
Although we assess the vendors' ability to fulfill contractual obligations prior to contract execution, any change in their solvency may impact overall cost and/or schedule of the project.

Economic evaluation
Subsequent changes in cost forecasts for emissions allowances, fuel, operating and maintenance expenses, construction costs, etc., may result in a different preferred compliance option.

Technical Feasibility
Although the air quality control technologies (AQCS) under consideration for this plan have been deployed at other coal generating units, the retrofit of any existing operating coal power plant comes with inherit design, construction, commissioning, and operability risk. Additionally, the design of an AQCS project of this magnitude (low NOx burners + SCR catalysts + precipitators + scrubbers) assumes the ability to meet required permitted emissions levels for NOx, SO_2, carbon monoxide (CO), mercury, sulfur trioxide (SO_3), and particulate matter.

Gypsum by-product disposal
The contract with a third-party to acquire by-products from the FGD process assumes a given quality and quantity of by-product. Additionally, the by-product customer is building a manufacturing facility adjacent to the Crystal River complex. Accordingly, our ability to dispose of the by-product may be impacted by the permitting and construction schedule of this facility.

Nuclear plant operations at Crystal River
The fossil units at the Crystal River complex are adjacent to the nuclear power plant and may be subject to enhanced security events that could halt or delay construction activities. Construction could also be impacted by NRC-imposed regulations or rules related to chemicals used in the operation of the compliance controls or gypsum facilities and/or enhanced background investigations for technical and craft personnel. Additionally, the construction activities related to the steam generator replacement and uprate plans may be concurrent with the CAIR construction schedule and could have an impact.

Turndown operations
The design of the new air quality control system is intended to allow the existing plant to meet its current minimum load requirements, however, actual results may differ from design and potential re-work or other plant needs might be necessary.

Performance targets
While the design of the compliance controls is intended to meet certain performance targets (emissions reduction, auxiliary power, duct pressure drop), the actual results may differ from the design targets and additional modifications, enhancements or improvements may result.

Start up and Commissioning
The retrofit of controls onto an existing operating plant may require operational refinements of both the generation and controls equipment to perform to its intended design. These refinements may result in schedule and/or cost changes.

Hazardous materials
The addition of the compliance controls and nearby gypsum plant will increase the level of certain chemicals during construction and operation, such as ammonia and natural gas, that will result in greater oversight of these and other hazardous materials.

Fabrication plant for fiberglass ductwork
The vendor providing the new fiberglass flue ductwork plans to manufacture the ductwork near Crystal River and their ability to acquire land, receive permits, and build the facility may impact the overall cost and schedule of the project.

Owner-supplied equipment
The performance (engineering, manufacturing, and delivery) of the owner-supplied equipment vendors, primarily the key compliance technologies, has a direct impact to the overall schedule and cost of the project. Any nonconformance or performance shortfalls by these vendors may result in claims or change orders by the EPC Contractor.

Warranty Risk
While our contractual arrangements contain warranty provisions, latent defects within the equipment or defects as a result of installation by the EPC Contractor may result in schedule and/or cost changes.

Third party damage
Damage to existing assets caused by third-parties during construction may have a negative impact on the operating units at Crystal River. A builder's risk insurance policy will be in place to cover potential damage to the new construction work while the existing plant will be covered under Progress' umbrella policy.

Quality assurance and control
While quality control and assurance is monitored throughout the design, manufacturing, and construction phases of the project, rework required during these phases may result in schedule and or cost changes.

Force Majeure

The Crystal River fossil units are located within proximity to the Gulf of Mexico at an elevation relatively close to sea level. The units are also located adjacent to an operating nuclear power plant. The design factor for the compliance controls is designed to withstand up to 120 mph winds. Accordingly, a catastrophic weather event may result in declaration of force majeure by vendors and/or contractors. Additionally, other events such as terrorism, nuclear accidents, enhanced security, storm surges, other causes of increases in sea level, labor halts for suppliers or contractors, transportation delays for major equipment and other events may result in declaration of force majeure. An event of Force Majeure may have a schedule and/or cost impact to the project.

Safety

Over the duration of the environmental compliance projects, we anticipate in excess of 2 million direct field craft man-hours to complete the construction efforts. While we will continue to foster our safety-oriented culture, the additional personnel and heavy equipment, in conjunction with the planned nuclear construction activities and ongoing plant operations, increases the potential of safety related events.

Conclusion

Given the uncertainties discussed above, as well as circumstances that may come to light in the future, PEF's compliance planning process is dynamic. As more information is developed, PEF will continue to evaluate compliance options in light of changed circumstances and, when appropriate, the Company will adjust the Integrated Clean Air Compliance Plan accordingly.

Appendix 1 Contracts

EPC Contract – Crystal River Units 4 & 5 Scrubber Project

Name of Counterparty: Environmental Projects Crystal River (EPCR) - a joint venture comprised of Zachry Construction Corporation (Zachry), Utility Engineering Corporation (a subsidiary of Zachry), and Burns & McDonnell, Inc.

Scope of Service: EPCR will be responsible for the engineering, procurement, construction and project management for the Flue Gas Desulphurization ("FGD") system and the Selective Catalytic Reduction ("SCR") system to be installed at Progress Energy Florida's ("PEF") Crystal River Plant, Units 4 & 5 that is not covered by PEF's other contractual arrangements with WorleyParsons, which has provided some preliminary engineering and procurement work for certain critical path elements, and with The Babcock & Wilcox Company, which has provided and will continue to provide certain process design and procurement work for portions of the SCR and FGD systems.

Selection Process:

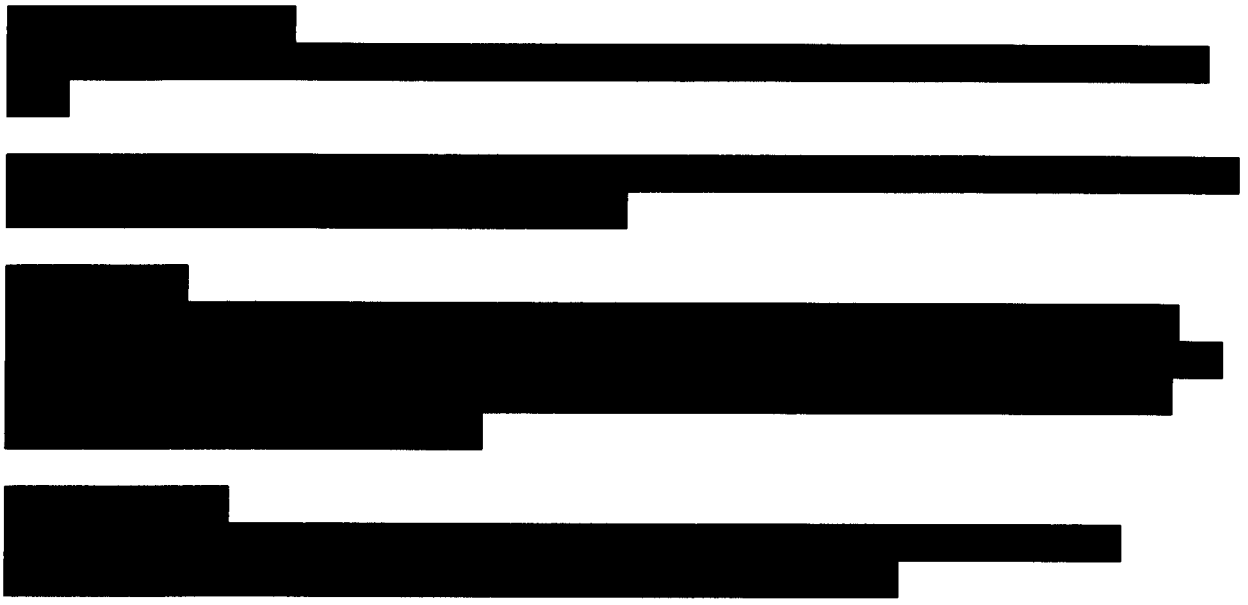
In May 2006, PEF issued an RFP to Zachry, Fluor Enterprises, Shaw Stone & Webster, Inc., and Bechtel Power Corporation, all of whom had been identified as qualified vendors who were interested in performing the extensive work required to implement PEF's CAIR Compliance Plan projects at Crystal River. The RFP required submittal of an open book, detailed cost breakdown structure aligned with an eventual conversion to a lump sum type format. The cost breakdowns were required to be submitted in a specific format so that the Company could review various components of the fixed price type structure, among other things, scope of supply, quantities, subcontracts, equipment, escalation rates, contingencies, fees, general and administrative ("G&A") costs, and indirect costs. The Company communicated with all four qualified vendors, but EPCR was the only bidder willing to provide a competitive open book type approach bid with the ability to convert to a lump sum, fixed price type format. Two of the bidders declined to provide a competitive bid and were only interested in working on an exclusive basis with the Company and one bidder determined that it did not have an available project team to support the project.

In November 2006, following a detailed review of the EPCR proposal and an evaluation of the capabilities of the EPCR partners, the parties executed a Letter of Intent (LOI) to provide time for PEF to further define the scope of the project so that detailed pricing could be developed and evaluated. The LOI has been extended and revised to provide a framework for the ongoing negotiations as well as the basis for preliminary engineering, procurement and initial site-related activities necessary to progress toward meeting the in-service dates of the various projects.

Cost: Under the LOI, PEF will pay Zachry up to [redacted] for costs associated with the Preliminary Work. To date, Zachry has provided indicative, lump sum pricing of approximately [redacted] for the EPC contract. The final price contract value will be determined at the completion of the contract negotiations.

LOI Terms & Conditions:

The LOI is limited in cost exposure with a not-to-exceed cap of [redacted] for costs associated with the Preliminary Work. PEF's intent in issuing the LOI is to have the Preliminary Work commence during the course of ongoing negotiations on the EPC Contract so that the project can be completed in a timely manner.



The Stebbins Engineering and Manufacturing Company

Name of Counterparty: The Stebbins Engineering and Manufacturing Company ("Stebbins")

Scope of Service: Design, fabricate, construct and assemble two Flue Gas Desulphurization Absorber Towers ("FGD Towers") for the Crystal River Units 4 & 5 scrubber project

Selection Process:

As part of Progress Energy Florida's ("PEF") compliance with CAIR and CAMR, PEF executed a contract with Stebbins for the design, fabrication, construction and assembly of the FGD Towers for the CR 4 & 5 scrubber project. PEF executed the contract to meet the current 2009 and 2010 in-service schedule and implement CAIR/CAMR compliance plan in the most cost-effective manner.

Stebbins is one of two companies that manufacture scrubber towers. PEF compared Stebbins' concrete and ceramic tile design against the other manufacturer's (The Babcock & Wilcox Company) alloy design. Based on overall cost, suitability for the Crystal River site, and prior experience with Stebbins, PEF selected Stebbins. PEF's sister utility, Progress Energy Carolinas ("PEC"), had used Stebbins to construct nearly identical towers at its Roxboro, Mayo and Asheville plants. Stebbins performed well and met schedules on these projects. By using Stebbins, PEF also takes take advantage of engineering efficiencies gained from PEC's experience and obtained a place in the tight production queue for such equipment. Further, PEF obtained a place in the tight production queue for such equipment. Based on the foregoing, PEF selected Stebbins to perform this work and executed a contract with Stebbins on January 24, 2007.

Cost: [redacted] 1

Principal Terms & Conditions

[redacted] 2 3

[redacted] 4 5 6 7 8

[redacted] 9 10

[redacted] 11

[redacted] 12



Commonwealth Dynamics, Inc.

Name of Counterparty: Commonwealth Dynamics, Inc. ("CDI")

Scope of Service: Design, fabricate and construct one Flue Gas Chimney ("FG Chimney") for the Crystal River Units 4 & 5 scrubber project

Selection Process:

As part of Progress Energy Florida's ("PEF") compliance with CAIR and CAMR, PEF executed a contract with CDI for the design, fabrication and construction of one FG Chimney for the CR 4 & 5 scrubber project. PEF executed the contract to meet the current 2009 and 2010 in-service schedule and implement CAIR/CAMR compliance plan in the most cost-effective manner.

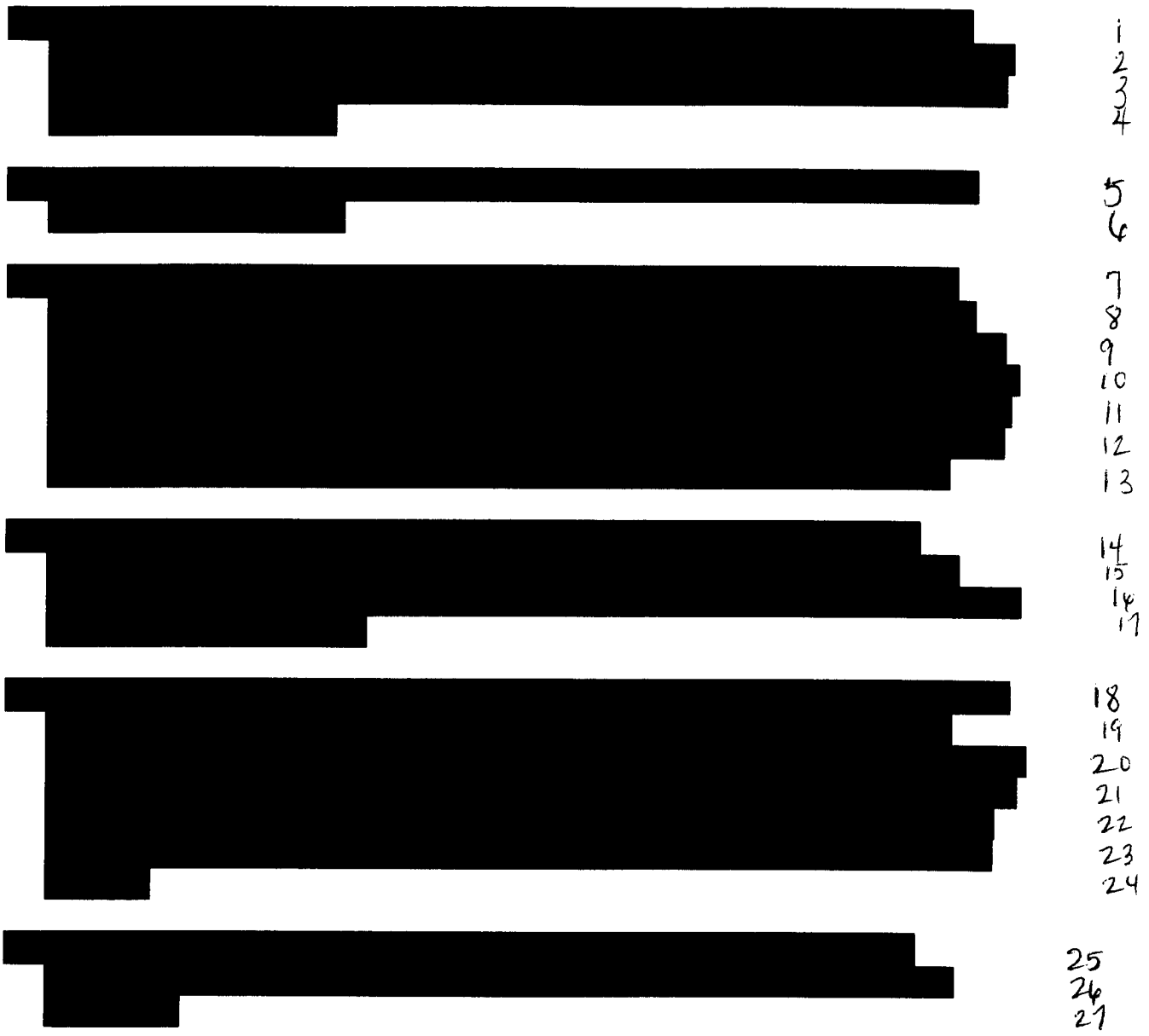
PEF selected of CDI to design and erect the Crystal River chimney on the basis of both competitive pricing and technical and commercial evaluations performed as part of the Progress Energy Carolina (PEC) scrubber program. Early in the PEC program, the Company reviewed the marketplace and found only three companies with the capability to design and manufacture Flue Gas chimneys for scrubber projects: CDI, Pullman Power, and Hamon-Custodis. PEC obtained proposals from those companies and after evaluation of appropriate competitive factors, including safety programs, cost, design, resource availability, and ability to meet required schedules, awarded the PEC chimney work to CDI. For Crystal River, PEF negotiated a price with CDI based on the PEC competitive prices adjusted for quantity differences and material, equipment, and labor escalation. At the time the Crystal River contract was negotiated, the market for chimney work had changed significantly since the PEC projects were bid. As more utilities initiated scrubber additions, the demand for the limited resources of three chimney erectors increased significantly along with corresponding escalation in material, equipment, and labor costs. During negotiations, CDI agreed to hold its profit, overhead, and contingency to those percentages that had won the competitive bids at PEC and adjust labor and material prices based on current market conditions. Negotiating a contract with CDI on this basis provided PEF an opportunity to "lock-in" the chimney work for Crystal River on a reasonable price basis and on a schedule that supported the needs of the Crystal River project. At the conclusion of the negotiations, PEF executed a contract for the Crystal River chimney with CDI on January 26, 2007.

Cost: [redacted] 1

Principal Terms & Conditions

[redacted] 2 3

[redacted] 4 5 6 7 8



CERAM Environmental, Inc.

Name of Counterparty: CERAM Environmental, Inc. ("CERAM")

Scope of Service: Design, fabrication, delivery and testing of the Selective Catalytic Reduction ("SCR") Catalyst for the Crystal River Units 4 & 5 scrubber project

Selection Process:

As part of Progress Energy Florida's ("PEF") compliance with CAIR and CAMR, PEF executed a contract with CERAM for the design, fabrication, and delivery of the SCR Catalyst for the Crystal River Unit 4 & 5 scrubber project. PEF executed the contract to meet the current 2009 and 2010 in-service schedule and implement CAIR/CAMR compliance plan in the most cost-effective manner.

PEF selected CERAM on a competitive bid basis and CERAM's ability to perform the work in accordance with PEF's specifications. On behalf of PEF, The Babcock & Wilcox Company ("B&W") reviewed the market and identified two potential vendors for the SCR Catalyst: CERAM and Cormetech, Inc. Both CERAM and Cormetech submitted bids for the design and manufacture of the SCR Catalyst. PEF determined that CERAM's bid provided the best offer, in terms of lowest cost and more favorable terms and conditions. PEF selected CERAM to negotiate a final agreement and executed a contract with CERAM on December 27, 2006.

Cost: [redacted] 1 2

Key Terms & Conditions

[redacted] 3 4

[redacted] 5 6 7

[redacted] 8 9

[redacted] 10 11 12

[redacted] 13 14 15 16 17



WorleyParsons Group, Inc.

Name of Counterparty: WorleyParsons Group, Inc. f/k/a Parsons Energy & Chemicals Group, Inc. ("WP")

Scope of Service:

Contract 114016, Work Authorization No. 24, Effective July 10, 2006. Work to be completed by the fourth quarter of 2006. Services for Units 4 and 5 steel support including detailed engineering and design.

Contract 114016, Work Authorization No. 24, Amendment No. 1, Effective November 30, 2006. Work to be completed by January 4, 2007. Additional engineering services for SCR steel design.

Contract 114016, Work Authorization No. 24, Amendment No. 2, Effective January 23, 2007. Increases dollar amount authorized for this work authorization.

Contract 114016, Work Authorization No. 25, Effective August 1, 2006. Work to be completed by December 31, 2007. SO3 mitigation study, preliminary engineering and procurement of limestone and gypsum handling system.

Contract 114016, Work Authorization No. 25, Amendment No. 1, Effective November 9, 2006. Howden ID fans.

Contract 114016, Work Authorization No. 26, Effective August 1, 2006. Work to be completed by December 31, 2007. Complete pressure transient study, bid evaluation for ID fans and motors, assist in EPC technical evaluation, scope finalization, review of EPC engineering documents, schedule and vendor documents.

Contract 114016, Work Authorization No. 29, Effective September 19, 2006. Establish costs and schedules to implement Continuous Mercury Monitoring Systems and integrate with the existing CEMS.

Contract 114016, Work Authorization No. 29, Amendment No. 1, Effective December 31, 2006. Extends completion date of Contract from December 31, 2006 to June 1, 2007.

Contract 114016, Work Authorization No. 42, Effective February 14, 2007. Provide procurement services for the purchase of ID Fans and Transformers for Units 4 & 5.

Selection Process:

As part of Progress Energy Florida's ("PEF") compliance with CAIR and CAMR, PEF entered into an alliance agreement with WP to furnish engineering, procurement and project management services for PEF's Flue Gas Desulphurization ("FGD") projects and FGD projects for Progress Energy Carolinas ("PEC"), PEF's sister utility. PEC first developed a short list of firms based on technical evaluations of statement of qualifications submitted by bidders. PEC then conducted interviews, site visits, and evaluations of additional information provided by the short-listed vendors to evaluate their experience, qualifications and project management programs. Based on this evaluation process, WP was selected as the Architect/Engineer.

After it became clear that CAIR would require installation of FGD and SCR controls on the Crystal River units, PEF became a party to the WP contract so that preliminary design and engineering work could begin expeditiously. On December 26, 2002, PEC entered into a master contract with WP. Progress Energy Service Company, acting as agent for PEF and PEC, amended and restated the master contract on July 10, 2006 (the "Master Contract") to meet the current 2009 and 2010 in-service schedule and implement CAIR/CAMR compliance plan in the most cost-effective manner.

Cost: [redacted]. 1

Principal Terms & Conditions

[redacted] 2 3

[redacted] 4 5

[redacted] 6 7

[redacted] 8 9 10

[redacted] 11 12 13

[redacted] 14 15 16 17 18

[redacted]

[redacted]

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5

The Babcock & Wilcox Company

Name of Counterparty: The Babcock & Wilcox Company ("B&W")

Scope of Service:

Contract 242070 executed July 14, 2005. Project planning, scheduling and engineering with PEF associated with the FGD and SCR work for the Crystal River Power Plant Project. – This Contract is closed. The work was authorized in Amendments 9, 16 and 17. [redacted] 1 2

Contract 119440, Amendment No. 9, Effective February 27, 2006 – amends contract to include Progress Energy Florida, Inc.

Contract 119440, Work Authorization 14, Effective April 20, 2006 – Authorizes B&W to order ball mills and absorber recycle pumps for Crystal River Units 4 & 5.

Contract 119440, Work Authorization 14, Amendment No. 1, Effective December 5, 2006 – Increases value of work order to cover additional LG and LD time equipment costs.

Contract 119440, Work Authorization 15, Effective May 1, 2006 – Crystal River Unit 4 Selective Catalytic Reduction - Authorizes B&W to continue design specifications, material selections, vendor supply evaluations, water balances, and purchasing critical long lead time equipment.

Contract 119440, Work Authorization 15, Amendment No. 1, Effective November 8, 2006 – Increases value of work order to cover cost of sonic horns at Crystal River Plant Unit 4.

Contract 119440, Work Authorization 15, Amendment No. 2, Effective January 1, 2007 – Increases value of work order to cover material and labor costs for Crystal River Unit 4 Selective Catalytic Reduction.

Contract 119440, Work Authorization 15, Amendment No. 3, Effective April 11, 2007 – Increases value of work to cover Engineering/PM Services.

Contract 119440, Work Authorization 16, Effective May 1, 2006 – Crystal River Unit 4 Flue Gas Desulphurization - Authorizes B&W to continue process design, general arrangement and equipment layout drawings, design specifications, material selections, vendor supply evaluations, water balances, limestone analyses and purchasing critical long lead time equipment.

Contract 119440, Work Authorization 16, Amendment No. 1, Effective October 16, 2006 – Increases value of work order to cover costs for the purchase of long lead time and common equipment used for Crystal River Unit 4 Flue Gas Desulphurization.

Contract 119440, Work Authorization 16, Amendment No. 2, Effective January 1, 2007 – Increases value of work order to cover costs for engineering/PM services and for procuring Unit 4 absorber oxidation air lances.

Contract 119440, Work Authorization 17, Effective May 1, 2006 – Crystal River Unit 5 Flue Gas Desulphurization - Authorized B&W to begin process design, general arrangement and equipment layout drawings, design specifications, material selections, vendor supply evaluations, water balances, limestone analyses and purchasing critical long lead time equipment.

Contract 119440, Work Authorization 17, Amendment No. 1, Effective October 16, 2006 – Increases value of work order to cover costs for the purchase of long lead time and common equipment used for Crystal River Unit 5 Flue Gas Desulphurization.

Contract 119440, Work Authorization 17, Amendment No. 2, Effective January 1, 2007 – Increased contract amount to cover costs for procuring Unit 5 FGD and common equipment.

Contract 119440, Work Authorization 19, Effective October 20, 2006 – Crystal River Unit 5 SCR - Authorized B&W to continue process design, general arrangement and equipment layout drawings, design specifications, material selections, vendor supply evaluations, water balances, limestone analyses and purchasing critical long lead time equipment.

Contract 119440, Work Authorization 19, Amendment No. 1, Effective January 1, 2007 – Increases value of work order to cover costs for engineering/PM services and for procuring Unit 5 Selective Catalytic Reduction.

Selection Process:

As part of Progress Energy Florida's ("PEF") compliance with CAIR and CAMR, PEC entered into an alliance agreement with B&W to furnish engineering, procurement and project management services for PEF's Flue Gas Desulphurization ("FGD") projects and FGD projects for Progress Energy Carolinas ("PEC"), PEF's sister utility. On March 14, 2003, PEC entered into a master contract with B&W (the "Master Contract"). PEC amended the Master Contract to add PEF as a party effective February 27, 2006, and to meet the current 2009 and 2010 in-service schedule and implement CAIR/CAMR compliance plan in the most cost-effective manner.

Cost: [redacted] 1

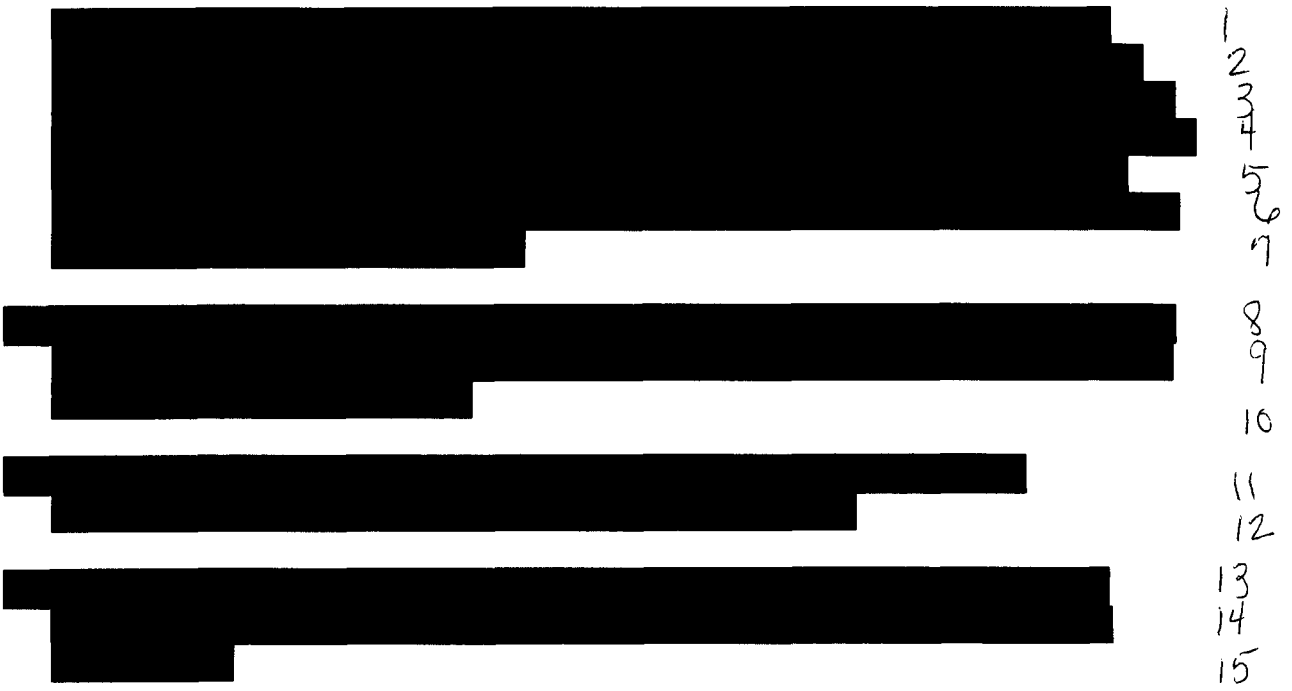
Principal Terms & Conditions

[redacted] 2 3

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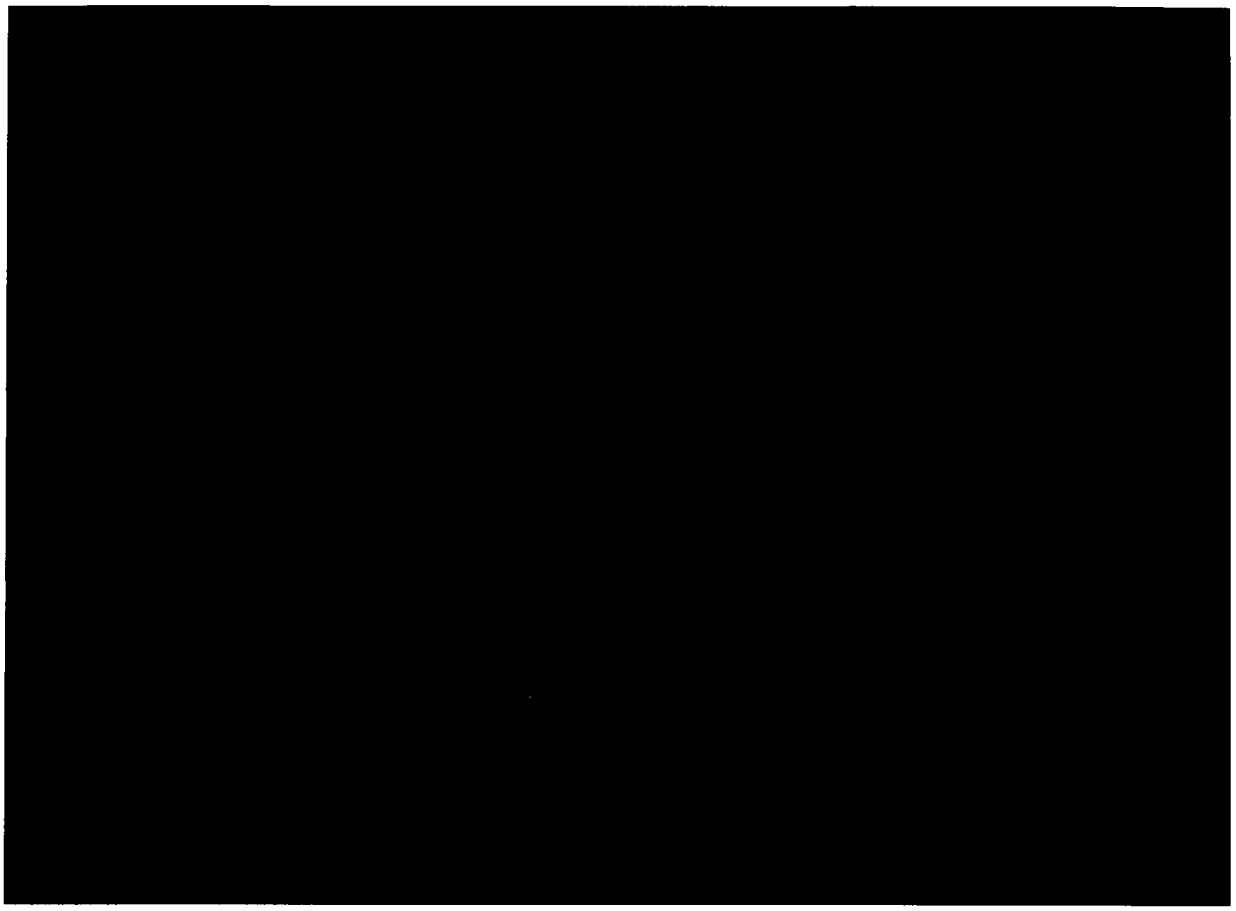


CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 31
COMPANY Progress Energy Florida
WITNESS Samual Waters (SSW-2)
DATE 11-06-07

Progress Energy Florida
Docket No. 070007-EI
Witness: Samuel S. Waters
Exhibit No. __ (SSW-2)

Summary of Alternative Compliance Plans – 2006

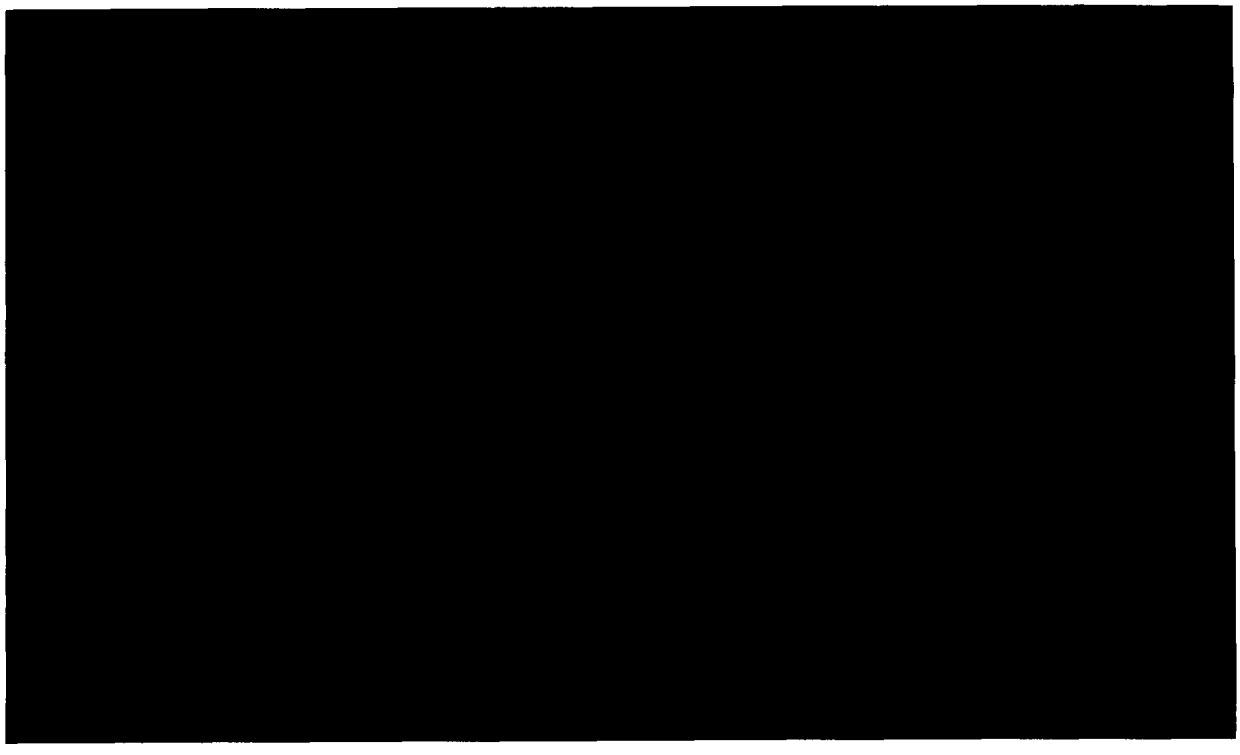


CONFIDENTIAL

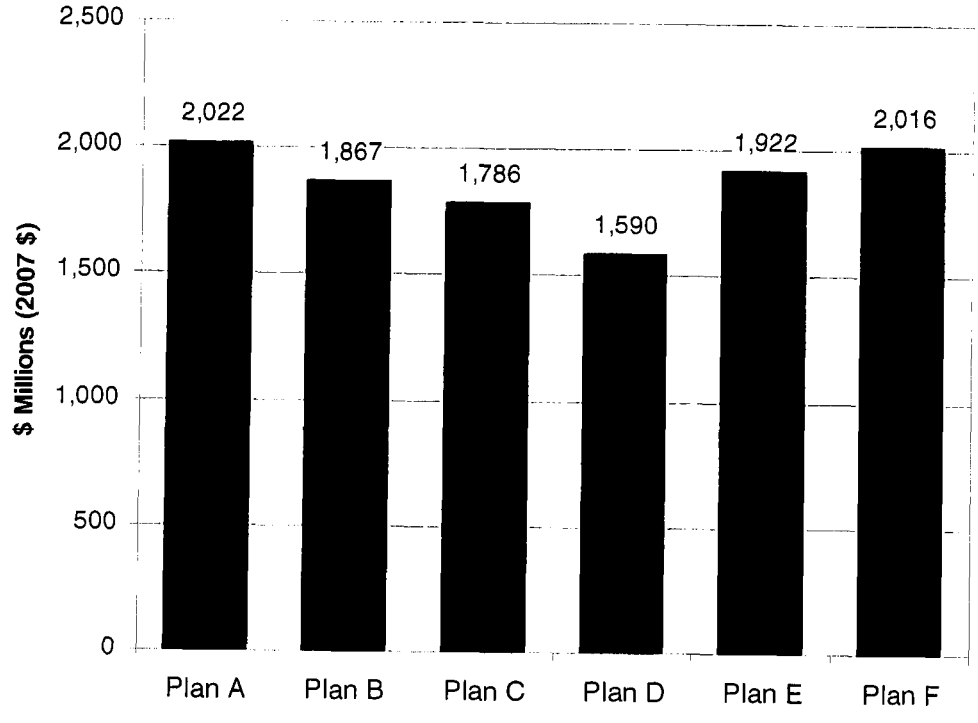
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 32
COMPANY Progress Energy Florida
WITNESS Samuel Waters (SSW-3)
DATE 11-06-07

Progress Energy Florida
Docket No. 070007-EI
Witness: Samuel S. Waters
Exhibit No. __ (SSW-3)

Summary of Alternative Compliance Plans – Current



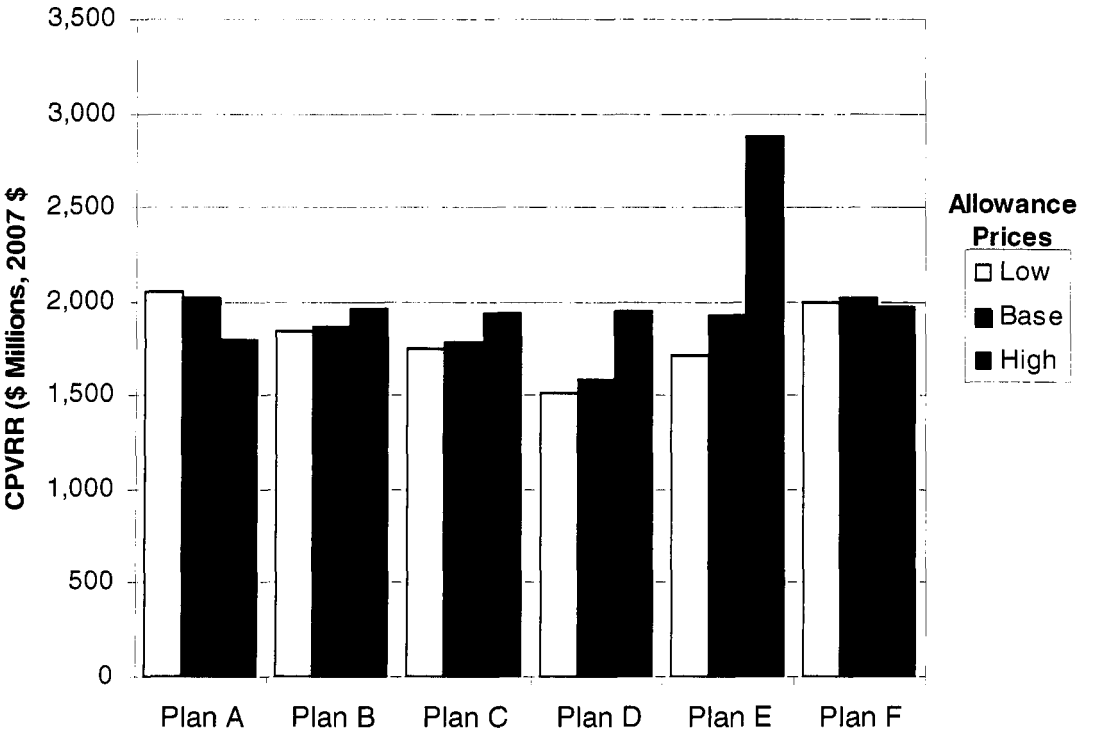
Comparison of Cumulative Present Value of Revenue Requirements



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 33
COMPANY Progress Energy Florida
WITNESS Samuel Waters (SSW-4)
DATE 11-06-07

Progress Energy Florida
Docket No. 070007-EI
Witness: Samuel S. Waters
Exhibit No. __ (SSW-5)

Impact of Allowance Price Uncertainty



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 34
COMPANY Progress Energy Florida
WITNESS Samuel Waters (SSW-5)
DATE 11-06-07

Docket 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit___(MI-1)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1E THROUGH 42-8E

JANUARY 2007 – DECEMBER 2007
Calculation of the Current Period Estimated/Actual Amount
Actuals for the period of January through June 2007
Estimated for the period of July through December 2007
DOCKET NO. 070007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI **EXHIBIT** 35
COMPANY Progress Energy Florida
WITNESS Maritza Iacono (MI-1)
DATE 11-06-07

PROGRESS ENERGY FLORIDA

Form 42-1E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$ (2,907,630)
2	Interest Provision (Form 42-2E, Line 6)	(425,900)
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 2008 to December 2008 (Lines 1 + 2 +3)	**$ (3,333,530)**

Docket 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit ___(MI-1)
Page 1 of 20

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Form 42-2E

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$3,589,145	$3,791,302	$3,628,304	$3,662,405	$3,938,399	$4,420,670	$5,225,323	$5,351,997	$5,371,942	$4,673,647	$4,031,656	$4,058,707	$51,743,497
2	True-Up Provision	($17,007,816)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(1,417,318)	(17,007,816)
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		2,171,827	2,373,984	2,210,986	2,245,087	2,521,081	3,003,352	3,808,005	3,934,679	3,954,624	3,256,329	2,614,338	2,641,389	34,735,681
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5A, Line 9)		1,291,085	3,157,215	2,405,128	2,509,070	3,324,031	3,548,168	3,068,626	3,728,981	5,118,838	3,324,162	2,701,214	1,565,017	35,741,535
	b. Capital Investment Projects (Form 42-7A, Line 9)		76,435	145,258	157,483	177,326	164,044	169,455	181,295	171,389	165,415	159,227	154,617	179,832	1,901,776
	c. Total Jurisdictional ECRC Costs		1,367,520	3,302,473	2,562,611	2,686,396	3,488,075	3,717,623	3,249,921	3,900,370	5,284,253	3,483,389	2,855,831	1,744,849	37,643,311
5	Over/(Under) Recovery (Line 3 - Line 4c)		804,307	(928,489)	(351,625)	(441,308)	(966,994)	(714,271)	558,084	34,309	(1,329,629)	(227,060)	(241,493)	896,540	(2,907,630)
6	Interest Provision (Form 42-3A, Line 10)		(59,047)	(53,235)	(50,064)	(45,812)	(42,889)	(40,643)	(35,022)	(27,637)	(24,372)	(21,668)	(16,558)	(8,953)	(425,900)
7	Beginning Balance True-Up & Interest Provision		(17,007,816)	(14,845,238)	(14,409,644)	(13,394,015)	(12,463,817)	(12,056,383)	(11,393,979)	(9,453,598)	(8,029,608)	(7,966,292)	(6,797,702)	(5,638,435)	(17,007,816)
	a. Deferred True-Up from January 2006 to December 2006 (Order No. PSC-06-0972-FOF-EI)		2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714	2,446,714
8	True-Up Collected/(Refunded) (see Line 2)		1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	1,417,318	17,007,816
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		(12,398,524)	(11,962,930)	(10,947,301)	(10,017,103)	(9,609,669)	(8,947,265)	(7,006,884)	(5,582,894)	(5,519,578)	(4,350,988)	(3,191,721)	(886,816)	(886,816)
10	Adjustments to Period Total True-Up Including Interest (a)		0	0	0	0	0	0	0	0	0	0	0	0	0
11	End of Period Total True-Up (Lines 9 + 10)		($12,398,524)	($11,962,930)	($10,947,301)	($10,017,103)	($9,609,669)	($8,947,265)	($7,006,884)	($5,582,894)	($5,519,578)	($4,350,988)	($3,191,721)	($886,816)	($886,816)

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Form 42-3E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Interest Provision
(in Dollars)

Line	Description	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	**($14,561,102)**	($12,398,524)	($11,962,930)	($10,947,301)	($10,017,103)	($9,609,669)	($8,947,265)	($7,006,884)	($5,582,894)	($5,519,578)	($4,350,988)	($3,191,721)	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	(12,339,477)	(11,909,695)	(10,897,237)	(9,971,291)	(9,566,780)	(8,906,622)	(6,971,862)	(5,555,257)	(5,495,206)	(4,329,320)	(3,175,163)	(877,863)	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	(26,900,579)	(24,308,219)	(22,860,167)	(20,918,593)	(19,583,883)	(18,516,290)	(15,919,127)	(12,562,142)	(11,078,100)	(9,848,897)	(7,526,151)	(4,069,583)	
4	Average True-Up Amount (Line 3 x 1/2)	(13,450,290)	(12,154,110)	(11,430,084)	(10,459,297)	(9,791,942)	(9,258,145)	(7,959,564)	(6,281,071)	(5,539,050)	(4,924,449)	(3,763,076)	(2,034,792)	
5	Interest Rate (First Day of Reporting Business Month)	5.27%	5.26%	5.26%	5.26%	5.26%	5.26%	5.28%	5.28%	5.28%	5.28%	5.28%	5.28%	
6	Interest Rate (First Day of Subsequent Business Month)	5.26%	5.26%	5.26%	5.26%	5.26%	5.28%	5.28%	5.28%	5.28%	5.28%	5.28%	5.28%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.53%	10.52%	10.52%	10.52%	10.52%	10.54%	10.56%	10.56%	10.56%	10.56%	10.56%	10.56%	
8	Average Interest Rate (Line 7 x 1/2)	5.265%	5.260%	5.260%	5.260%	5.260%	5.270%	5.280%	5.280%	5.280%	5.280%	5.280%	5.280%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.439%	0.438%	0.438%	0.438%	0.438%	0.439%	0.440%	0.440%	0.440%	0.440%	0.440%	0.440%	
10	Interest Provision for the Month (Line 4 x Line 9)	($59,047)	($53,235)	($50,064)	($45,812)	($42,889)	($40,643)	($35,022)	($27,637)	($24,372)	($21,668)	($16,558)	($8,953)	**($425,900)**

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PROGRESS ENERGY FLORIDA

Form 42 4E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

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 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$2,652,554	$1,544,960	$1,107,594	72%
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	3,971,507	2,802,660	1,168,847	42%
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	17,001,677	15,991,000	1,010,677	6%
	3a Pipeline Integrity Management	788,427	277,000	511,427	185%
	4 Above Ground Tank Secondary Containment	540	0	540	N/A
	5 SO2 Emissions Allowances	9,047,737	11,476,805	(2,429,068)	-21%
	6 Phase II Cooling Water Intake	477,858	1,409,057	(931,199)	-66%
	8 Arsenic Groundwater Standard - Base	8,053	77,669	(69,616)	-90%
	9 Sea Turtle - Coastal Street Lighting - Distrib	122,558	475,000	(352,442)	-74%
	11 Modular Cooling Towers - Base	3,318,461	3,336,752	(18,291)	-1%
2	Total O&M Activities - Recoverable Costs	$37,389,373	$37,390,903	($1,530)	0%
3	Recoverable Costs Allocated to Energy	9,047,737	11,476,805	(2,429,068)	-21%
4	Recoverable Costs Allocated to Demand	28,341,636	25,914,098	2,427,538	9%

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 2007 through December 2007

Form 42-5E

O&M Activities
(in Dollars)

Line	Description	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Description of O&M Activities													
1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$239,677	$404,052	$186,759	$67,204	$200,747	$415,202	$189,819	$189,819	$189,819	$189,819	$189,819	$189,819	$2,652,554
1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	204,636	287,009	347,827	249,279	731,100	55,969	348,945	348,945	348,945	348,945	350,963	348,945	3,971,507
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	209,427	1,850,001	1,281,512	1,577,149	1,678,820	1,044,151	913,936	1,522,436	3,414,936	1,983,936	1,333,436	191,936	17,001,677
3a	Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	28,552	7,972	17,666	20,449	17,513	14,275	25,000	62,000	100,000	152,500	157,500	185,000	788,427
4	Above Ground Tank Secondary Containment - Intm	0	0	0	0	540	0	0	0	0	0	0	0	540
5	SO2 Emissions Allowances	679,649	686,895	647,751	554,484	747,975	870,997	843,384	890,156	878,394	733,033	768,198	746,825	9,047,737
6	Phase II Cooling Water Intake 316(b) - Base	0	12,500	0	54,096	0	564	20,000	0	11,750	0	11,750	0	110,660
6a	Phase II Cooling Water Intake 316(b) - Intm	58,231	76,707	10,985	43,650	34,105	28,520	35,000	35,000	10,000	35,000	0	0	367,198
8	Arsenic Groundwater Standard - Base	0	0	0	0	0	0	0	0	0	0	0	8,053	8,053
9	Sea Turtle - Coastal Street Lighting - Distrib	0	0	646	4,675	15,400	1,837	16,667	16,667	16,667	16,667	16,666	16,666	122,558
11a	Modular Cooling Towers - Base	(18,290)	0	0	0	0	1,370,452	834,188	834,188	297,924	0	0	0	3,318,461
2	Total of O&M Activities	1,401,881	3,325,136	2,493,146	2,570,986	3,426,199	3,801,967	3,226,938	3,899,210	5,268,434	3,459,899	2,828,332	1,687,243	$37,389,373
3	Recoverable Costs Allocated to Energy	679,649	686,895	647,751	554,484	747,975	870,997	843,384	890,156	878,394	733,033	768,198	746,825	9,047,737
4	Recoverable Costs Allocated to Demand - Transm	239,677	404,052	186,759	67,204	200,747	415,202	189,819	189,819	189,819	189,819	189,819	189,819	2,652,554
	Recoverable Costs Allocated to Demand - Distrib	414,063	2,137,011	1,629,986	1,831,103	2,425,320	1,101,957	1,279,548	1,888,048	3,780,548	2,349,548	1,701,065	557,547	21,095,743
	Recoverable Costs Allocated to Demand - Prod-Base	(18,290)	12,500	0	54,096	0	1,371,016	854,188	834,188	309,674	0	11,750	8,053	3,437,175
	Recoverable Costs Allocated to Demand - Prod-Intm	86,783	84,679	28,651	64,099	52,158	42,795	60,000	97,000	110,000	187,500	157,500	185,000	1,156,165
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Retail Energy Jurisdictional Factor	0.96820	0.96800	0.96830	0.96760	0.97000	0.96250	0.96276	0.96139	0.95884	0.95748	0.96002	0.96666	
6	Retail Transmission Demand Jurisdictional Factor	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	
	Retail Distribution Demand Jurisdictional Factor	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
	Retail Production Demand Jurisdictional Factor - Base	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
	Retail Production Demand Jurisdictional Factor - Intm	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
	Retail Production Demand Jurisdictional Factor - Peaking	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
7	Jurisdictional Energy Recoverable Costs (A)	658,036	664,914	627,217	536,518	725,535	838,335	811,973	855,784	842,239	701,865	737,484	721,925	8,721,825
8	Jurisdictional Demand Recoverable Costs - Transm (B)	169,205	285,248	131,846	47,444	141,721	293,120	134,007	134,007	134,007	134,007	134,007	134,007	1,872,626
	Jurisdictional Demand Recoverable Costs - Distrib (B)	412,394	2,128,398	1,623,417	1,823,724	2,415,546	1,097,516	1,274,391	1,880,439	3,765,312	2,340,079	1,694,210	555,300	21,010,726
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	(17,148)	11,719	0	50,717	0	1,285,369	800,827	782,076	290,329	0	11,016	7,550	3,222,455
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	68,598	66,936	22,648	50,667	41,229	33,828	47,428	76,675	86,951	148,211	124,497	146,235	913,903
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,291,085	$3,157,215	$2,405,128	$2,509,070	$3,324,031	$3,548,168	$3,068,626	$3,728,981	$5,118,838	$3,324,162	$2,701,214	$1,565,017	$35,741,535

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 2007 through December 2007

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-Intermediate	$408,288	$461,703	($53,415)	-12%
	4.x Above Ground Tank Secondary Containment	632,425	625,878	6,547	1%
	5 SO2/NOx Emissions Allowances	656,912	(195,726)	852,638	436%
	7.x CAIR/CAMR	184,493	207,296	(22,803)	-11%
	9 Sea Turtle - Coastal Street Lighting -Distribution	950	42,893	(41,943)	-98%
	10.x Underground Storage Tanks-Base	42,029	58,077	(16,048)	-28%
	11 Modular Cooling Towers - Base	198,074	143,644	54,430	38%
2	Total Capital Investment Activities - Recoverable Costs	2,123,171	1,343,765	$779,406	58%
3	Recoverable Costs Allocated to Energy	656,912	(195,726)	$852,638	-436%
4	Recoverable Costs Allocated to Demand	$1,466,259	$1,539,491	($73,232)	-5%

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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Form 42-7E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Description of Investment Projects (A)													
	3b Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$9,860	$36,410	$36,335	$36,259	$36,219	$36,178	$36,157	$36,192	$36,243	$36,221	$36,145	$36,069	$408,288
	4.1 Above Ground Tank Secondary Containment - Peaking	40,390	35,600	47,337	60,123	47,257	51,635	51,589	53,742	55,056	55,293	55,556	56,254	609,832
	4.2 Above Ground Tank Secondary Containment - Base	486	468	467	466	465	463	462	461	460	459	457	456	5,570
	4.3 Above Ground Tank Secondary Containment - Intermediate	0	0	0	0	0	0	376	1,193	2,128	2,898	4,692	5,736	17,023
	5 SO2 Emissions Allowances - Energy	10,427	63,038	62,924	70,260	66,617	66,044	68,753	60,311	51,678	43,908	36,744	56,208	656,912
	7.1 CAIR/CAMR - Intermediate	598	598	598	599	604	607	607	607	607	745	1,020	1,295	8,485
	7.2 CAIR/CAMR - Peaking	5,671	6,198	7,870	9,408	11,643	14,562	16,630	17,923	18,611	19,190	19,696	24,897	172,299
	7.3 CAIR/CAMR - Base	0	0	0	0	0	0	2,094	323	323	323	323	323	3,709
	9 Sea Turtle - Coastal Street Lighting -Distribution	0	0	0	0	0	33	93	123	141	159	177	224	950
	10.1 Underground Storage Tanks-Base	2,394	2,397	2,400	2,400	2,129	1,858	2,775	2,539	2,534	2,528	2,523	2,518	28,995
	10.2 Underground Storage Tanks-Intermediate	1,069	1,083	1,066	1,066	947	1,328	1,085	1,082	1,080	1,078	1,076	1,074	13,034
	11 Modular Cooling Towers - Base	14,445	15,200	15,687	15,797	15,710	15,627	22,463	16,872	16,751	16,629	16,507	16,385	198,074
2	Total Investment Projects - Recoverable Costs	85,340	160,992	174,684	196,378	181,591	188,335	203,084	191,368	185,612	179,431	174,917	201,439	2,123,171
3	Recoverable Costs Allocated to Energy	10,427	63,038	62,924	70,260	66,617	66,044	68,753	60,311	51,678	43,908	36,744	56,208	656,912
	Recoverable Costs Allocated to Distribution Demand	0	0	0	0	0	33	93	123	141	159	177	224	950
4	Recoverable Costs Allocated to Demand - Production - Base	17,325	18,065	18,554	18,663	18,304	17,948	25,700	19,872	19,745	19,616	19,487	19,359	232,639
	Recoverable Costs Allocated to Demand - Production - Intermediate	11,527	38,091	37,999	37,924	37,770	38,113	38,225	39,074	40,058	40,942	42,933	44,174	446,830
	Recoverable Costs Allocated to Demand - Production - Peaking	46,061	41,798	55,207	69,531	58,900	66,197	68,219	71,665	73,667	74,483	75,252	81,151	782,131
5	Retail Energy Jurisdictional Factor	0.96820	0.96800	0.96830	0.96760	0.97000	0.96250	0.96276	0.96139	0.95884	0.95748	0.96002	0.96666	
	Retail Distribution Demand Jurisdictional Factor	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
6	Retail Demand Jurisdictional Factor - Production - Base	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
7	Jurisdictional Energy Recoverable Costs (B)	10,095	61,021	60,929	67,983	64,619	63,567	66,192	57,982	49,551	42,041	35,275	54,334	633,590
	Jurisdictional Demand Recoverable Costs (B)	0	0	0	0	0	33	93	123	140	158	176	223	946
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	16,243	16,936	17,395	17,497	17,161	16,827	24,095	18,631	18,512	18,391	18,270	18,150	218,106
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	9,112	30,109	30,037	29,977	29,856	30,127	30,215	30,886	31,664	32,363	33,937	34,918	353,201
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	40,985	37,191	49,123	61,868	52,409	58,901	60,701	63,767	65,548	66,274	66,958	72,207	695,932
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$76,435	$145,258	$157,483	$177,326	$164,044	$169,455	$181,295	$171,389	$165,415	$159,227	$154,617	$179,832	$1,901,776

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 2007 through December 2007

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 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$6,259	$0	$10,000	$10,000	$4,000	$0	$0	$0	$30,259
	b. Clearings to Plant		0	0	0	0	0	0	0	0	24,000	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	$2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,674,588	2,698,588	2,698,588	2,698,588	2,698,588	
3	Less: Accumulated Depreciation	($172,057)	(178,899)	(185,742)	(192,584)	(199,427)	(206,269)	(213,112)	(219,954)	(226,797)	(233,670)	(240,574)	(247,477)	(254,381)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	6,259	6,259	16,259	26,259	6,259	6,259	6,259	6,259	
5	Net Investment (Lines 2 + 3 + 4)	2,502,531	2,495,688	2,488,846	2,482,004	2,475,161	2,474,578	2,467,735	2,470,893	2,474,050	2,471,178	2,464,274	2,457,370	2,450,466	
6	Average Net Investment		2,499,110	2,492,267	2,485,425	2,478,582	2,474,869	2,471,157	2,469,314	2,472,472	2,472,614	2,467,726	2,460,822	2,453,918	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		23,242	23,178	23,114	23,051	23,016	22,982	22,965	22,994	22,995	22,950	22,886	22,821	$276,194
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		4,248	4,237	4,225	4,214	4,207	4,201	4,198	4,203	4,203	4,195	4,183	4,172	50,487
8	Investment Expenses														
	a. Depreciation (C) 3.07%		6,842	6,842	6,842	6,842	6,842	6,842	6,842	6,842	6,873	6,904	6,904	6,904	82,324
	b. Amortization		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 (D)		(24,473)	2,152	2,152	2,152	2,152	2,152	2,152	2,152	2,172	2,172	2,172	2,172	(718)
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		9,860	36,410	36,335	36,259	36,219	36,178	36,157	36,192	36,243	36,221	36,145	36,069	408,288
	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		9,860	36,410	36,335	36,259	36,219	36,178	36,157	36,192	36,243	36,221	36,145	36,069	408,288
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)		0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)		7,794	28,781	28,721	28,661	28,630	28,597	28,581	28,608	28,649	28,631	28,571	28,511	322,735
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,794	$28,781	$28,721	$28,661	$28,630	$28,597	$28,581	$28,608	$28,649	$28,631	$28,571	$28,511	$322,735

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Lines 2 x 89% @ .009773 x 1/12 + 11%@ .008723 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2005 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

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Progress Energy Florida
Witness: M. Iacono
Exhibit ___ (MI-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - PEAKING (Project 4.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$4,822	$232,073	$72,119	$65,056	$511,575	$102,207	$46,587	$20,000	$21,600	$40,000	$27,000	$118,800	$1,261,840
	b. Clearings to Plant			0	0	251,899	2,984	0	97,710	0	886,554	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	
				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$474,071	474,071	474,071	2,340,200	2,343,184	2,343,184	2,440,894	2,440,894	3,327,448	3,327,448	3,327,448	3,327,448	3,327,448	
3	Less: Accumulated Depreciation		(31,519)	(33,333)	(35,072)	(57,610)	(64,474)	(71,338)	(78,963)	(86,044)	(94,306)	(103,751)	(113,196)	(122,641)	(132,085)	
4	CWIP - Non-Interest Bearing		2,473,260	2,478,082	2,710,155	916,146	978,218	1,489,793	1,494,290	1,540,877	674,323	695,923	735,923	762,923	881,723	
5	Net Investment (Lines 2 + 3 + 4)		$2,915,812	2,918,820	3,149,155	3,198,736	3,256,928	3,761,640	3,856,222	3,895,727	3,907,465	3,919,620	3,950,175	3,967,731	4,077,086	
6	Average Net Investment			2,917,316	3,033,988	3,165,965	3,227,832	3,509,284	3,808,657	3,875,975	3,901,596	3,913,542	3,934,897	3,958,952	4,022,408	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		34,547	28,216	29,232	30,019	32,636	35,421	36,047	36,285	36,396	36,595	36,818	37,408	$409,620
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		6,314	5,158	5,344	5,487	5,966	6,475	6,589	6,633	6,653	6,689	6,730	6,838	74,877
8	Investment Expenses															
	a. Depreciation (C)			1,814	1,739	6,578	22,824	6,864	7,627	7,081	8,263	9,445	9,445	9,445	9,445	100,567
	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 (D)			(2,285)	488	6,182	1,793	1,793	2,114	1,873	2,563	2,563	2,563	2,563	2,563	24,772
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			40,390	35,600	47,337	60,123	47,257	51,635	51,589	53,742	55,056	55,293	55,556	56,254	609,836
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			40,390	35,600	47,337	60,123	47,257	51,635	51,589	53,742	55,056	55,293	55,556	56,254	609,836
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
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)			35,939	31,677	42,120	53,497	42,049	45,944	45,903	47,819	48,988	49,199	49,433	50,054	542,622
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$35,939	$31,677	$42,120	$53,497	$42,049	$45,944	$45,903	$47,819	$48,988	$49,199	$49,433	$50,054	$542,622

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)		$33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	
3	Less: Accumulated Depreciation (C)		(4,549)	(4,661)	(4,772)	(4,883)	(4,994)	(5,105)	(5,216)	(5,327)	(5,439)	(5,550)	(5,661)	(5,772)	(5,883)	
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)		$28,543	28,431	28,320	28,209	28,098	27,987	27,876	27,765	27,653	27,542	27,431	27,320	27,209	
6	Average Net Investment			28,487	28,376	28,265	28,154	28,042	27,931	27,820	27,709	27,598	27,487	27,376	27,264	$0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		265	264	263	262	261	260	259	258	257	256	255	254	3,111
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		48	48	48	48	48	47	47	47	47	47	47	46	569
8	Investment Expenses															
	a. Depreciation (C)			111	111	111	111	111	111	111	111	111	111	111	111	1,334
	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 (D)			61	45	45	45	45	45	45	45	45	45	45	45	557
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			486	468	467	466	465	463	462	461	460	459	457	456	5,570
	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			486	468	467	466	465	463	462	461	460	459	457	456	5,570
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			456	439	438	437	436	434	433	432	431	430	428	428	5,222
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$456	$439	$438	$437	$436	$434	$433	$432	$431	$430	$428	$428	$5,222

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$68,413	$80,000	$90,000	$50,000	$30,000	$0	$318,413
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	318,413	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	318,413	318,413	
3	Less: Accumulated Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	(894)	(2,683)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	68,413	148,413	238,413	288,413	0	0	
5	Net Investment (Lines 2+ 3 + 4)		$0	0	0	0	0	0	0	68,413	148,413	238,413	288,413	317,519	315,730	
6	Average Net Investment			0	0	0	0	0	0	34,207	108,413	193,413	263,413	302,966	316,625	0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		0	0	0	0	0	0	318	1,008	1,799	2,450	2,818	2,945	11,337
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	58	184	329	448	515	538	2,072
8	Investment Expenses															
	a. Depreciation (C)			0	0	0	0	0	0	0	0	0	0	894	1,788	2,683
	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 (D)			0	0	0	0	0	0	0	0	0	0	465	465	930
	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	376	1,193	2,128	2,898	4,692	5,736	17,022
	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	376	1,193	2,128	2,898	4,692	5,736	17,022
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)			0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)			0	0	0	0	0	0	297	943	1,682	2,291	3,709	4,534	13,456
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$297	$943	$1,682	$2,291	$3,709	$4,534	$13,456

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

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Progress Energy Florida
Witness: M. Iacono
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO2 Emission Allowance Inventory		$1,942,701	$11,634,783	$10,919,619	$10,243,599	$9,660,846	$8,884,602	$7,985,335	$7,113,683	$6,195,258	$5,288,595	$4,527,293	$3,730,826	$2,955,732	$2,955,732
	b. 25401FL Auctioned SO2 Allowance		(6,115,691)	(6,087,422)	(6,059,153)	(6,030,883)	(6,002,614)	(7,072,910)	(7,044,641)	(7,016,371)	(6,988,102)	(6,959,832)	(6,931,563)	(6,903,294)	(2,019,940)	(2,019,940)
	c. 1581002 NOx Emission Allowance Inventory		0	521,500	532,140	1,835,330	3,068,228	3,574,093	5,681,533	5,780,919	5,880,305	5,979,691	6,079,077	6,178,463	6,277,849	6,277,849
2	Total Working Capital		($4,172,991)	6,068,861	5,392,606	6,048,045	6,726,459	5,385,784	6,622,227	5,878,230	5,087,461	4,308,453	3,674,807	3,005,995	7,213,640	7,213,640
3	Average Net Investment			947,935	5,730,734	5,720,326	6,387,252	6,056,122	6,004,006	6,250,229	5,482,846	4,697,957	3,991,630	3,340,401	5,109,818	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		8,816	53,296	53,199	59,401	56,322	55,837	58,127	50,990	43,691	37,122	31,066	47,521	$555,389
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		1,611	9,742	9,725	10,858	10,295	10,207	10,625	9,321	7,987	6,786	5,679	8,687	101,523
5	Total Return Component (B)			10,427	63,038	62,924	70,260	66,617	66,044	68,753	60,311	51,678	43,908	36,744	56,208	656,912
6	Expense Dr (Cr)															
	a. 5090001 SO2 allowance expense			707,918	715,164	676,020	582,753	776,244	899,266	871,653	918,425	906,663	761,302	796,467	775,094	9,386,970
	b. 4074004 Amortization Expense			($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($28,269)	($339,233)
7	Net Expense (C)			679,649	686,895	647,751	554,484	747,975	870,997	843,384	890,156	878,394	733,033	768,198	746,825	9,047,737
8	Total System Recoverable Expenses (Lines 5 + 7)			690,076	749,933	710,674	624,743	814,592	937,041	912,136	950,467	930,071	776,941	804,942	803,033	9,704,649
	a. Recoverable costs allocated to Energy			690,076	749,933	710,674	624,743	814,592	937,041	912,136	950,467	930,071	776,941	804,942	803,033	9,704,649
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96820	0.96800	0.96830	0.96760	0.97000	0.96250	0.96276	0.96139	0.95884	0.95748	0.96002	0.96666	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)			668,131	725,935	688,146	604,502	790,154	901,902	878,164	913,766	891,790	743,906	772,760	776,259	9,355,416
12	Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 668,131	$ 725,935	$ 688,146	$ 604,502	$ 790,154	$ 901,902	$ 878,164	$ 913,766	$ 891,790	$ 743,906	$ 772,760	$ 776,259	$ 9,355,416

Notes:
(A) Lines 3 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 Rate Case Settlement in Dkt. 050078-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9.
(E) Line 8b x Line 10.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Intermediate (Project 7.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			($1)	$0	$0	$317	$458	$123	$0	$0	$0	$25,000	$25,000	$25,000	$75,897
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		54,328	54,326	54,326	54,326	54,644	55,102	55,225	55,225	55,225	55,225	80,225	105,225	130,225	
5	Net Investment (Lines 2+ 3 + 4)		$54,328	54,326	54,326	54,326	54,644	55,102	55,225	55,225	55,225	55,225	80,225	105,225	130,225	
6	Average Net Investment			54,327	54,326	54,326	54,485	54,873	55,163	55,225	55,225	55,225	67,725	92,725	117,725	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		505	505	505	507	510	513	514	514	514	630	862	1,095	$7,174
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		92	92	92	93	93	94	94	94	94	115	158	200	1,311
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			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	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)			598	598	598	599	604	607	607	607	607	745	1,020	1,295	8,485
	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			598	598	598	599	604	607	607	607	607	745	1,020	1,295	8,485
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 (Intm)			0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)			473	473	473	473	477	480	480	480	480	589	806	1,024	6,707
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$473	$473	$473	$473	$477	$480	$480	$480	$480	$589	$806	$1,024	$6,707

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

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Progress Energy Florida
Witness: M. Iacono
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Peaking (Project 7.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$21,336	$74,589	$229,647	$49,978	$356,103	$174,806	$200,979	$34,250	$90,921	$14,000	$78,195	$28,090	$1,352,895
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	1,857,723	
	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	
				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	1,857,723	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(3,141)	
4	CWIP - Non-Interest Bearing		504,830	526,165	600,755	830,401	880,380	1,236,483	1,411,290	1,612,269	1,646,519	1,737,440	1,751,440	1,829,635	1	
5	Net Investment (Lines 2 + 3 + 4)		$504,830	526,165	600,755	830,401	880,380	1,236,483	1,411,290	1,612,269	1,646,519	1,737,440	1,751,440	1,829,635	1,854,583	
6	Average Net Investment			515,498	563,460	715,577	855,391	1,058,432	1,323,888	1,511,780	1,629,394	1,691,979	1,744,440	1,790,538	1,842,109	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		4,794	5,240	6,655	7,955	9,843	12,312	14,060	15,153	15,735	16,223	16,652	17,132	$141,755
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		876	958	1,216	1,454	1,799	2,251	2,570	2,770	2,876	2,966	3,044	3,132	$25,912
8	Investment Expenses															
	a. Depreciation (C)			0	0	0	0	0	0	0	0	0	0	0	3,141	3,141
	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 (D)			0	0	0	0	0	0	0	0	0	0	0	1,492	1,492
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			5,671	6,198	7,870	9,408	11,643	14,562	16,630	17,923	18,611	19,190	19,696	24,897	172,300
	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			5,671	6,198	7,870	9,408	11,643	14,562	16,630	17,923	18,611	19,190	19,696	24,897	172,300
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)			0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
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)			5,046	5,515	7,003	8,371	10,360	12,957	14,797	15,948	16,560	17,075	17,525	22,153	153,310
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$5,046	$5,515	$7,003	$8,371	$10,360	$12,957	$14,797	$15,948	$16,560	$17,075	$17,525	$22,153	$153,310

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base (Project 7.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$8,034	$6,094	$473	$226	$0	$0	$0	$0	$0	$0	$0	$0	**$14,826**
	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 (A)			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	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		14,527	22,561	28,655	29,128	29,353	29,353	29,353	29,353	29,353	29,353	29,353	29,353	29,353	
5	Net Investment (Lines 2 + 3 + 4)		14,527	22,561	28,655	29,128	29,353	29,353	29,353	29,353	29,353	29,353	29,353	29,353	29,353	
6	Average Net Investment			18,544	25,608	28,891	29,240	29,353	29,353	29,353	29,353	29,353	29,353	29,353	29,353	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		0	0	0	0	0	0	1,770	273	273	273	273	273	$3,135
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	324	50	50	50	50	50	573
8	Investment Expenses															
	a. Depreciation (C)	3.19%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.016338		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	2,094	323	323	323	323	323	3,709
	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	2,094	323	323	323	323	323	3,709
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			0	0	0	0	0	0	1,963	303	303	303	303	303	3,477
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$1,963	$303	$303	$303	$303	$303	$3,477

Notes:
(A) Credit reflecting expenses recovered through base rates for breakers that were replaced to compensate for increased load due to the Modular Cooling Towers.
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 5 year life of project, as stated in Dkt. 060162-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 Rate Case Settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA

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Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base - AFUDC (Project 7.4)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$7,946,137	$13,624,716	$9,081,506	$10,794,393	$9,974,205	$17,940,663	$11,300,993	$23,898,707	$28,005,709	$39,831,952	$36,914,419	$69,755,348	$281,068,749
	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 (B)	8.848%		228,999	310,212	396,210	(308,711)	245,920	300,720	538,876	667,661	856,662	1,103,566	1,390,953	1,786,606	
2	Plant-in-Service/Depreciation Base		$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-AFUDC Interest Bearing Accrual		27,084,694	35,259,830	49,194,759	58,672,475	69,158,157	79,378,282	97,619,665	109,459,534	134,025,902	162,888,273	203,823,793	244,129,165	315,671,119	
5	Net Investment (Lines 2 + 3 + 4)		$27,084,694	35,259,830	49,194,759	58,672,475	69,158,157	79,378,282	97,619,665	109,459,534	134,025,902	162,888,273	203,823,793	244,129,165	315,671,119	
6	Average Net Investment			31,172,262	42,227,295	53,933,617	63,915,316	74,268,219	88,498,973	103,539,599	121,742,718	148,457,087	183,356,033	223,976,479	279,900,142	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	6.82%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.03% x 1/12)	2.03%		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes			0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor			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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
12	Retail Energy-Related Recoverable Costs			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) This schedule shown for informational purposes.
(B) AFUDC calculation based on 2005 Rate Case Settlement in Dkt. 050078-EI.

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Progress Energy Florida
Witness: M. Iacono
Exhibit___(MI-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$6,035	$1,667	$1,667	$1,667	$1,667	$1,667	$1,665	$16,035
	b. Clearings to Plant		0	0	0	0	0	0	6,035	0	0	0	0	10,000	
	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	$0	0	0	0	0	0	0	6,035	6,035	6,035	6,035	6,035	16,035	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	(12)	(35)	(58)	(81)	(104)	(146)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	6,035	1,667	3,334	5,001	6,668	8,335	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	6,035	7,690	9,334	10,978	12,622	14,266	15,889	
6	Average Net Investment		0	0	0	0	0	3,017	6,863	8,512	10,156	11,800	13,444	15,077	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		0	0	0	0	0	28	64	79	94	110	125	140	$640
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	0	0	5	12	14	17	20	23	26	117
8	Investment Expenses														
	a. Depreciation (C) 4.59%		0	0	0	0	0	0	12	23	23	23	23	42	146
	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 (D) 0.011545		0	0	0	0	0	0	6	6	6	6	6	15	44
	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	33	93	123	141	159	177	224	950
	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	33	93	123	141	159	177	224	950
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 - (Distribution)		0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
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)		0	0	0	0	0	33	93	123	140	158	176	223	946
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$33	$93	$123	$140	$158	$176	$223	$946

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

Docket 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit ___(MI-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - BASE (Project 10.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$559	$0	$0	($49,259)	$0	$0	$0	$0	$0	$0	$0	($48,700)
	b. Clearings to Plant			0	0	0	0	0	0	168,941	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		$0	0	0	0	0	0	0	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	(690)	(1,151)	(1,611)	(2,071)	(2,532)	(2,992)	
4	CWIP - Non-Interest Bearing		217,641	217,641	218,200	218,200	218,200	168,941	168,941	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$217,641	217,641	218,200	218,200	218,200	168,941	168,941	168,251	167,791	167,330	166,870	166,410	165,949	
6	Average Net Investment			217,641	217,921	218,200	218,200	193,571	168,941	168,596	168,021	167,561	167,100	166,640	166,179	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		2,024	2,027	2,029	2,029	1,800	1,571	1,568	1,563	1,558	1,554	1,550	1,545	$20,819
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		370	370	371	371	329	287	287	286	285	284	283	283	3,806
8	Investment Expenses															
	a. Depreciation (C)			0	0	0	0	0	0	690	460	460	460	460	460	2,992
	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 (D)			0	0	0	0	0	0	230	230	230	230	230	230	1,380
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,394	2,397	2,400	2,400	2,129	1,858	2,775	2,539	2,534	2,528	2,523	2,518	28,997
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,394	2,397	2,400	2,400	2,129	1,858	2,775	2,539	2,534	2,528	2,523	2,518	28,997
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			2,244	2,247	2,250	2,250	1,996	1,742	2,602	2,380	2,376	2,370	2,365	2,361	27,184
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,244	$2,247	$2,250	$2,250	$1,996	$1,742	$2,602	$2,380	$2,376	$2,370	$2,365	$2,361	$27,184

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

Docket 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit ___(MI-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - INTERMEDIATE (10.2)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$5,635	($3,155)	$0	$0	($21,609)	$599	$0	$0	$0	$0	$0	$0	($18,530)
	b. Clearings to Plant		0	0	0	0	0	75,868	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	$0	0	0	0	0	0	75,868	75,868	75,868	75,868	75,868	75,868	75,868	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	(1,109)	(1,310)	(1,512)	(1,714)	(1,915)	(2,117)	(2,319)	
4	CWIP - Non-Interest Bearing	94,398	100,033	96,879	96,879	96,879	75,269	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$94,398	100,033	96,879	96,879	96,879	75,269	74,759	74,558	74,356	74,154	73,953	73,751	73,549	
6	Average Net Investment		97,216	98,456	96,879	96,879	86,074	74,859	74,658	74,457	74,255	74,053	73,852	73,650	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		904	916	901	901	800	(131)	694	692	691	689	687	685	$8,429
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		165	167	165	165	146	(24)	127	127	126	126	126	125	1,541
8	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	1,111	202	202	202	202	202	202	2,321
	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 (D)		0	0	0	0	0	372	62	62	62	62	62	62	743
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,069	1,083	1,066	1,066	947	1,328	1,085	1,082	1,080	1,078	1,076	1,074	13,033
	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		1,069	1,083	1,066	1,066	947	1,328	1,085	1,082	1,080	1,078	1,076	1,074	13,033
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)		0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)		845	856	843	843	749	1,050	858	855	854	852	851	849	10,303
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$845	$856	$843	$843	$749	$1,050	$858	$855	$854	$852	$851	$849	$10,303

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

Docket 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit ___(MI-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2007 through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: MODULAR COOLING TOWERS - BASE (Project 11)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 07	Actual February 07	Actual March 07	Actual April 07	Actual May 07	Actual June 07	Estimated July 07	Estimated August 07	Estimated September 07	Estimated October 07	Estimated November 07	Estimated December 07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$62,994	$68,001	$37,753	($645)	$2,081	$0	($22,267)	$0	$0	$0	$0	$0	**$147,916**
	b. Clearings to Plant		0	0	0	0	0	0	147,916	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	(3,829)	(851)	(851)	(851)	(851)	(851)	
2	Plant-in-Service/Depreciation Base	**$516,221**	516,221	516,221	516,221	516,221	516,221	516,221	664,137	664,137	664,137	664,137	664,137	664,137	
3	Less: Accumulated Depreciation	**(64,528)**	(73,131)	(81,735)	(90,339)	(98,942)	(107,546)	(116,150)	(135,848)	(146,917)	(157,986)	(169,055)	(180,124)	(191,192)	
4	CWIP - Non-Interest Bearing	**0**	62,994	130,995	168,748	168,102	170,183	170,183	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	**$451,693**	506,083	565,481	594,630	585,381	578,858	570,254	528,290	517,221	506,152	495,083	484,014	472,945	
6	Average Net Investment		478,888	535,782	580,055	590,005	582,119	574,556	549,272	522,755	511,686	500,617	489,548	478,479	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		4,454	4,983	5,395	5,487	5,414	5,343	4,130	4,862	4,759	4,656	4,553	4,450	$58,484
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		814	911	986	1,003	990	977	755	889	870	851	832	813	10,690
8	Investment Expenses														
	a. Depreciation (C) 20.00%		8,604	8,604	8,604	8,604	8,604	8,604	19,698	11,069	11,069	11,069	11,069	11,069	126,665
	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 (D) 0.016338		574	703	703	703	703	703	1,709	904	904	904	904	904	10,318
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8) (E)		14,445	15,200	15,687	15,797	15,710	15,627	22,463	16,872	16,751	16,629	16,507	16,385	198,074
	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		14,445	15,200	15,687	15,797	15,710	15,627	22,463	16,872	16,751	16,629	16,507	16,385	198,073
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)		0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)		13,543	14,250	14,707	14,810	14,729	14,651	21,060	15,818	15,705	15,590	15,476	15,361	185,699
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$13,543	$14,250	$14,707	$14,810	$14,729	$14,651	$21,060	$15,818	$15,705	$15,590	$15,476	$15,361	$185,699

Notes:
(A) Credit reflecting expenses recovered through base rates for breakers that were replaced to compensate for increased load due to the Modular Cooling Towers.
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 5 year life of project, as stated in Dkt. 060162-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9 - Line 1d. This calculation started in July when appropriate treatment was determined and included true-ups for any unrecoverable amounts prior to July 2007.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Source:
Line 8c Based on 2005 Rate Case Settlement in Dkt. 050078-EI.

Docket 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit___(MI-2)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
CAPITAL PROGRAM DETAIL

JANUARY 2007 – DECEMBER 2007
Calculation of the Current Period Estimated/Actual Amount
Actuals for the period of January through June 2007
Estimated for the period of July through December 2007
DOCKET NO. 070007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 36
COMPANY Progress Energy Florida
WITNESS Martha Iacono (MI-2)
DATE 11-06-07

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	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	$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	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	
5	Net Investment (Lines 2 + 3 + 4)	$673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	
6	Average Net Investment		673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	$75,189
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	13,744
8	Investment Expenses														
	a. Depreciation 1.86%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.010864		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)		7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	88,934
	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		7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	88,934

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	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	$153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	
3	Less: Accumulated Depreciation	(20,420)	(20,844)	(21,268)	(21,692)	(22,116)	(22,540)	(22,964)	(23,388)	(23,812)	(24,236)	(24,660)	(25,084)	(25,508)	
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)	$133,278	132,854	132,430	132,006	131,582	131,158	130,734	130,310	129,886	129,462	129,038	128,614	128,190	
6	Average Net Investment		133,066	132,642	132,218	131,794	131,370	130,946	130,522	130,098	129,674	129,250	128,826	128,402	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,238	1,234	1,230	1,226	1,222	1,218	1,214	1,210	1,206	1,202	1,198	1,194	$14,590
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		226	225	225	224	223	223	222	221	220	220	219	218	2,667
8	Investment Expenses														
	a. Depreciation 3.31%		424	424	424	424	424	424	424	424	424	424	424	424	5,087
	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 0.009773		(1,253)	125	125	125	125	125	125	125	125	125	125	125	124
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		635	2,008	2,004	1,999	1,994	1,990	1,985	1,980	1,976	1,971	1,966	1,962	22,468
	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		635	2,008	2,004	1,999	1,994	1,990	1,985	1,980	1,976	1,971	1,966	1,962	22,468

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Base

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	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	$33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	
3	Less: Accumulated Depreciation	(4,549)	(4,661)	(4,772)	(4,883)	(4,994)	(5,105)	(5,216)	(5,327)	(5,439)	(5,550)	(5,661)	(5,772)	(5,883)	
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)	$28,543	28,431	28,320	28,209	28,098	27,987	27,876	27,765	27,653	27,542	27,431	27,320	27,209	
6	Average Net Investment		28,487	28,376	28,265	28,154	28,042	27,931	27,820	27,709	27,598	27,487	27,376	27,264	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		265	264	263	262	261	260	259	258	257	256	255	254	$3,111
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		48	48	48	48	48	47	47	47	47	47	47	46	569
8	Investment Expenses														
	a. Depreciation 4.03%		111	111	111	111	111	111	111	111	111	111	111	111	1,334
	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 0.016338		61	45	45	45	45	45	45	45	45	45	45	45	557
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		486	468	467	466	465	463	462	461	460	459	457	456	5,570
	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		486	468	467	466	465	463	462	461	460	459	457	456	5,570

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	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	$0	0	0	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	
3	Less: Accumulated Depreciation	0	0	0	(20,520)	(25,080)	(29,641)	(34,201)	(38,761)	(43,321)	(47,881)	(52,442)	(57,002)	(61,562)	
4	CWIP - Non-Interest Bearing	1,614,230	1,614,230	1,614,230	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$1,614,230	1,614,230	1,614,230	1,593,710	1,589,150	1,584,590	1,580,029	1,575,469	1,570,909	1,566,349	1,561,789	1,557,228	1,552,668	
6	Average Net Investment		1,614,230	1,614,230	1,595,990	1,591,430	1,586,870	1,582,309	1,577,749	1,573,189	1,568,629	1,564,069	1,559,508	1,554,948	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		22,518	15,012	14,832	14,800	14,758	14,715	14,673	14,631	14,588	14,546	14,503	14,461	$183,838
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		4,116	2,744	2,675	2,705	2,698	2,690	2,682	2,674	2,667	2,659	2,651	2,643	33,605
8	Investment Expenses														
	a. Depreciation 3.39%		0	0	4,560	20,520	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	61,562
	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 0.008160		0	0	5,489	1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098	15,368
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		26,635	17,757	27,356	39,124	23,113	23,063	23,013	22,963	22,913	22,863	22,812	22,762	294,373
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		26,635	17,757	27,356	39,124	23,113	23,063	23,013	22,963	22,913	22,863	22,812	22,762	294,373

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	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	$178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	
3	Less: Accumulated Depreciation	(2,435)	(2,957)	(3,477)	(3,998)	(4,518)	(5,039)	(5,559)	(6,079)	(6,600)	(7,120)	(7,641)	(8,161)	(8,681)	
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)	$176,502	175,981	175,461	174,940	174,420	173,899	173,379	172,859	172,338	171,818	171,297	170,777	170,257	
6	Average Net Investment		176,242	175,721	175,200	174,680	174,160	173,639	173,119	172,598	172,078	171,558	171,037	170,517	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,635	1,634	1,629	1,625	1,620	1,615	1,610	1,605	1,600	1,595	1,591	1,586	$19,345
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		299	299	298	297	296	295	294	293	293	292	291	290	3,536
8	Investment Expenses														
	a. Depreciation 3.49%		521	520	520	520	520	520	520	520	520	520	520	520	6,246
	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 0.010473		(830)	156	156	156	156	156	156	156	156	156	156	156	888
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,625	2,610	2,604	2,598	2,592	2,587	2,581	2,575	2,569	2,564	2,558	2,552	30,015
	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		1,625	2,610	2,604	2,598	2,592	2,587	2,581	2,575	2,569	2,564	2,558	2,552	30,015

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$90	$41,457	$34,271	$2,984	$97,710	$0	$0	$0	$21,600	$40,000	$27,000	$118,800	$383,911
	b. Clearings to Plant		0	0	251,899	2,984	0	97,710	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	251,899	254,883	254,883	352,593	352,593	352,593	352,593	352,593	352,593	352,593	
3	Less: Accumulated Depreciation	0	0	0	(279)	(844)	(1,409)	(2,736)	(3,517)	(4,299)	(5,080)	(5,862)	(6,644)	(7,425)	
4	CWIP - Non-Interest Bearing	176,081	176,171	217,628	0	(0)	97,710	(0)	(0)	(0)	21,600	61,600	88,600	207,400	
5	Net Investment (Lines 2 + 3 + 4)	$176,081	176,171	217,628	251,620	254,039	351,183	349,858	349,075	348,294	369,112	408,331	434,549	552,567	
6	Average Net Investment		176,126	196,900	234,624	252,829	302,611	350,248	349,467	348,685	358,703	388,721	421,440	493,558	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,638	1,831	2,182	2,351	2,814	3,257	3,250	3,243	3,336	3,615	3,919	4,590	$36,027
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		299	335	399	430	514	595	594	593	610	661	716	839	6,586
8	Investment Expenses														
	a. Depreciation 2.66%		0	0	279	565	565	1,328	782	782	782	782	782	782	7,426
	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 0.009773		0	0	205	208	208	528	287	287	287	287	287	287	2,871
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,937	2,166	3,065	3,554	4,101	5,708	4,913	4,904	5,014	5,345	5,705	6,498	52,911
	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		1,937	2,166	3,065	3,554	4,101	5,708	4,913	4,904	5,014	5,345	5,705	6,498	52,911

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$4,732	$190,616	$37,849	$62,072	$413,866	$102,207	$46,587	$20,000	$0	$0	$0	$0	$877,929
	b. Clearings to Plant		0	0	0	0	0	0	0	886,554	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	886,554	886,554	886,554	886,554	886,554	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	(1,182)	(3,546)	(5,910)	(8,275)	(10,639)	
4	CWIP - Non-Interest Bearing	8,625	13,357	203,974	241,822	303,894	717,760	819,967	866,554	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$8,625	13,357	203,974	241,822	303,894	717,760	819,967	866,554	885,372	883,007	880,643	878,279	875,915	
6	Average Net Investment		10,991	108,665	222,898	272,858	510,827	768,863	843,260	875,963	884,189	881,825	879,461	877,097	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		102	1,011	2,073	2,538	4,751	7,150	7,842	8,146	8,223	8,201	8,179	8,157	$66,373
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		19	185	379	464	868	1,307	1,434	1,489	1,503	1,499	1,495	1,491	12,133
8	Investment Expenses														
	a. Depreciation 3.20%		0	0	0	0	0	0	0	1,182	2,364	2,364	2,364	2,364	10,639
	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 0.009345		0	0	0	0	0	0	0	690	690	690	690	690	3,452
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		121	1,195	2,452	3,001	5,619	8,457	9,276	11,508	12,781	12,755	12,729	12,703	92,597
	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		121	1,195	2,452	3,001	5,619	8,457	9,276	11,508	12,781	12,755	12,729	12,703	92,597

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	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	$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	584	584	584	584	584	584	584	584	584	584	584	584	584	
5	Net Investment (Lines 2 + 3 + 4)	$584	584	584	584	584	584	584	584	584	584	584	584	584	
6	Average Net Investment		584	584	584	584	584	584	584	584	584	584	584	584	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		5	5	5	5	5	5	5	5	5	5	5	5	$65
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		1	1	1	1	1	1	1	1	1	1	1	1	12
8	Investment Expenses														
	a. Depreciation 2.33%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.010864		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)		6	6	6	6	6	6	6	6	6	6	6	6	77
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		6	6	6	6	6	6	6	6	6	6	6	6	77

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	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	$141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	
3	Less: Accumulated Depreciation	(8,664)	(9,532)	(10,326)	(11,121)	(11,915)	(12,710)	(13,504)	(14,298)	(15,093)	(15,887)	(16,682)	(17,476)	(18,270)	
4	CWIP - Non-Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$132,771	131,903	131,108	130,314	129,520	128,725	127,931	127,136	126,342	125,548	124,753	123,959	123,164	
6	Average Net Investment		132,337	131,506	130,711	129,917	129,122	128,328	127,534	126,739	125,945	125,150	124,356	123,562	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,145	1,223	1,216	1,208	1,201	1,193	1,186	1,179	1,171	1,164	1,157	1,149	$14,191
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		209	224	222	221	220	218	217	215	214	213	211	210	2,594
8	Investment Expenses														
	a. Depreciation 6.74%		868	794	794	794	794	794	794	794	794	794	794	794	9,607
	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 0.017522		(202)	207	207	207	207	207	207	207	207	207	207	207	2,069
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,020	2,447	2,439	2,430	2,421	2,413	2,404	2,395	2,386	2,378	2,369	2,360	28,461
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,020	2,447	2,439	2,430	2,421	2,413	2,404	2,395	2,386	2,378	2,369	2,360	28,461

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Intermediate

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$68,413	$80,000	$90,000	$50,000	$30,000	$0	$318,413
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	318,413	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	318,413	318,413	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(894)	(2,683)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	68,413	148,413	238,413	288,413	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	68,413	148,413	238,413	288,413	317,519	315,730	
6	Average Net Investment		0	0	0	0	0	0	34,207	108,413	193,413	263,413	302,966	316,625	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	318	1,008	1,799	2,450	2,818	2,945	$11,337
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		0	0	0	0	0	0	58	184	329	448	515	538	2,072
8	Investment Expenses														
	a. Depreciation 3.34%		0	0	0	0	0	0	0	0	0	0	894	1,788	2,683
	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 0.008723		0	0	0	0	0	0	0	0	0	0	465	465	930
	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	376	1,193	2,128	2,898	4,692	5,736	17,022
	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	376	1,193	2,128	2,898	4,692	5,736	17,022

For Project: CAIR/CAMR - CRYSTAL RIVER NORTH - 4 & 5 (Project 7.4)
(in Dollars)

Calculated @ AFUDC - *Not applicable to ECRC revenue reqmts. until placed in service.*

Line	Description	Base	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	Investments															
	a. Expenditures/Additions			$7,946,137	$13,624,716	$9,081,506	$10,794,393	$9,974,205	$17,940,663	$11,300,993	$23,898,707	$28,005,709	$39,831,952	$38,914,419	$69,755,348	$281,068,748
	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	8.848%		228,999	310,212	396,210	(308,711)	245,920	300,720	538,876	667,661	856,662	1,103,568	1,390,953	1,786,606	7,517,677
2	Plant-in-Service/Depreciation Base		$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 - AFUDC-Interest Bearing		27,084,694	35,259,830	49,194,759	58,672,475	69,158,157	79,378,282	97,619,665	109,459,534	134,025,902	162,888,273	203,823,793	244,129,165	315,671,119	288,586,425
5	Net Investment (Lines 2 + 3 + 4)		$27,084,694	35,259,830	49,194,759	58,672,475	69,158,157	79,378,282	97,619,665	109,459,534	134,025,902	162,888,273	203,823,793	244,129,165	315,671,119	
6	Average Net Investment			31,172,262	42,227,295	53,933,617	63,915,316	74,268,219	88,498,973	103,539,599	121,742,718	148,457,087	183,356,033	223,976,479	279,900,142	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxe	6.819%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.029% x 1/1	2.029%		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.27%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.016338		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2007 through December 2007
CAIR/CAMR (Projects 7.1 and 7.3 Recap)

For Project: CAIR/CAMR - ANCLOTE (Project 7.1)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		($1)	$0	$0	$317	$458	$123	$0	$0	$0	$25,000	$25,000	$25,000	$75,897
	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	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	54,328	54,326	54,326	54,326	54,644	55,102	55,225	55,225	55,225	55,225	80,225	105,225	130,225	
5	Net Investment (Lines 2 + 3 + 4)	$54,328	54,326	54,326	54,326	54,644	55,102	55,225	55,225	55,225	55,225	80,225	105,225	130,225	
6	Average Net Investment		54,327	54,326	54,326	54,485	54,873	55,163	55,225	55,225	55,225	67,725	92,725	117,725	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxe 11.16%		505	505	505	507	510	513	514	514	514	630	862	1,095	$7,174
	b. Debt Component (Line 6 x 2.57% x 1/12 2.04%		92	92	92	93	93	94	94	94	94	115	158	200	1,311
8	Investment Expenses														
	a. Depreciation 2.21%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.008723		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)		598	598	598	599	604	607	607	607	607	745	1,020	1,295	8,485
	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		598	598	598	599	604	607	607	607	607	745	1,020	1,295	8,485

Docket 070007-E
Progress Energy Florida
Witness: M. Iacono
Exhibit ___(MI-2)
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For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

ALL Peaking

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$979	$356	$49,024	($2,614)	$48,015	$22,963	$9,500	$1,000	$1,500	$1,500	$11,000	$1,500	$144,723
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	161,334	
	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	161,334	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(121)	
4	CWIP - Non-Interest Bearing	16,611	17,590	17,946	66,970	64,356	112,371	135,334	144,834	145,834	147,334	148,834	159,834	0	
5	Net Investment (Lines 2 + 3 + 4)	$16,611	17,590	17,946	66,970	64,356	112,371	135,334	144,834	145,834	147,334	148,834	159,834	161,213	
6	Average Net Investment		17,101	17,768	42,458	65,663	88,364	123,853	140,084	145,334	146,584	148,084	154,334	160,523	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		159	165	395	611	822	1,152	1,303	1,352	1,363	1,377	1,435	1,493	$11,626
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		29	30	72	112	150	211	238	247	249	252	262	273	2,125
8	Investment Expenses														
	a. Depreciation 1.80%		0	0	0	0	0	0	0	0	0	0	0	121	121
	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 0.010473		0	0	0	0	0	0	0	0	0	0	0	141	141
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		188	195	467	722	972	1,362	1,541	1,599	1,612	1,629	1,698	2,028	14,013
	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		188	195	467	722	972	1,362	1,541	1,599	1,612	1,629	1,698	2,028	14,013

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	investments														
	a. Expenditures/Additions		$6,991	$14,305	$14,503	$8,816	$16,002	$15,830	$10,000	$1,500	$1,500	$1,500	$18,450	$1,500	$110,896
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	268,824	
	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	268,824	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(479)	
4	CWIP - Non-Interest Bearing	157,927	164,918	179,223	193,726	202,542	218,543	234,374	244,374	245,874	247,374	248,874	267,324	0	
5	Net Investment (Lines 2 + 3 + 4)	$157,927	164,918	179,223	193,726	202,542	218,543	234,374	244,374	245,874	247,374	248,874	267,324	268,344	
6	Average Net Investment		161,423	172,070	186,474	198,134	210,542	226,458	239,374	245,124	246,624	248,124	258,099	267,834	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,501	1,600	1,734	1,843	1,958	2,106	2,226	2,280	2,294	2,308	2,400	2,491	$24,741
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		274	293	317	337	358	385	407	417	419	422	439	455	4,522
8	Investment Expenses														
	a. Depreciation 4.28%		0	0	0	0	0	0	0	0	0	0	0	479	479
	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 0.009773		0	0	0	0	0	0	0	0	0	0	0	219	219
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,776	1,893	2,051	2,179	2,316	2,491	2,633	2,696	2,713	2,729	2,839	3,645	29,961
	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		1,776	1,893	2,051	2,179	2,316	2,491	2,633	2,696	2,713	2,729	2,839	3,645	29,961

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$434	$16,275	$6,812	$168	$6,313	$19,282	$9,500	$1,500	$1,500	$2,500	$20,850	$1,500	**$86,634**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	187,110	
	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	187,110	
3	Less: Accumulated Depreciation	**0**	0	0	0	0	0	0	0	0	0	0	0	(234)	
4	CWIP - Non-Interest Bearing	**100,476**	100,910	117,185	123,997	124,165	130,478	149,760	159,260	160,760	162,260	164,760	185,610	0	
5	Net Investment (Lines 2 + 3 + 4)	**$100,476**	100,910	117,185	123,997	124,165	130,478	149,760	159,260	160,760	162,260	164,760	185,610	186,876	
6	Average Net Investment		100,693	109,048	120,591	124,081	127,322	140,119	154,510	160,010	161,510	163,510	175,185	186,243	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes **11.16%**		936	1,014	1,121	1,154	1,184	1,303	1,437	1,488	1,502	1,521	1,629	1,732	$16,022
	b. Debt Component (Line 6 x 2.57% x 1/12) **2.04%**		171	185	205	211	216	238	263	272	275	278	298	317	2,929
8	Investment Expenses														
	a. Depreciation **3.00%**		0	0	0	0	0	0	0	0	0	0	0	234	234
	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 **0.009773**		0	0	0	0	0	0	0	0	0	0	0	152	152
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,108	1,200	1,327	1,365	1,401	1,541	1,700	1,760	1,777	1,799	1,927	2,435	19,337
	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		1,108	1,200	1,327	1,365	1,401	1,541	1,700	1,760	1,777	1,799	1,927	2,435	19,337

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$180	$690	$642	$4,330	$5,369	$24,954	$55,825	$3,000	$1,500	$1,500	$2,500	$17,590	**$118,079**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	121,748	
	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	121,748	
3	Less: Accumulated Depreciation	**0**	0	0	0	0	0	0	0	0	0	0	0	(151)	
4	CWIP - Non-Interest Bearing	**3,669**	3,849	4,539	5,180	9,510	14,879	39,833	95,658	98,658	100,158	101,658	104,158	0	
5	Net Investment (Lines 2 + 3 + 4)	**$3,669**	3,849	4,539	5,180	9,510	14,879	39,833	95,658	98,658	100,158	101,658	104,158	121,597	
6	Average Net Investment		3,759	4,194	4,859	7,345	12,195	27,356	67,745	97,158	99,408	100,908	102,908	112,877	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes **11.16%**		35	39	45	68	113	254	630	904	924	938	957	1,050	$5,959
	b. Debt Component (Line 6 x 2.57% x 1/12) **2.04%**		6	7	8	12	21	47	115	165	169	172	175	192	1,089
8	Investment Expenses														
	a. Depreciation **2.98%**		0	0	0	0	0	0	0	0	0	0	0	151	151
	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 **0.010864**		0	0	0	0	0	0	0	0	0	0	0	110	110
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		41	46	53	81	134	301	745	1,069	1,093	1,110	1,132	1,503	7,309
	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		41	46	53	81	134	301	745	1,069	1,093	1,110	1,132	1,503	7,309

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$6,044	$20,905	$103,646	$5,075	$15,642	$15,157	$23,237	$1,500	$1,500	$2,500	$20,895	$1,500	**$217,601**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	307,486	
	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	307,486	
3	Less: Accumulated Depreciation	**0**	0	0	0	0	0	0	0	0	0	0	0	(500)	
4	CWIP - Non-Interest Bearing	**89,885**	95,930	116,835	220,480	225,555	241,197	256,354	279,591	281,091	282,591	285,091	305,986	0	
5	Net Investment (Lines 2 + 3 + 4)	**$89,885**	95,930	116,835	220,480	225,555	241,197	256,354	279,591	281,091	282,591	285,091	305,986	306,987	
6	Average Net Investment		92,908	106,382	168,658	223,018	233,376	248,776	267,973	280,341	281,841	283,841	295,539	306,487	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes **11.16%**		864	989	1,569	2,074	2,170	2,314	2,492	2,607	2,621	2,640	2,749	2,850	$25,939
	b. Debt Component (Line 6 x 2.57% x 1/12) **2.04%**		158	181	287	379	397	423	456	477	479	483	502	521	4,742
8	Investment Expenses														
	a. Depreciation **3.90%**		0	0	0	0	0	0	0	0	0	0	0	500	500
	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 **0.009773**		0	0	0	0	0	0	0	0	0	0	0	250	250
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,022	1,170	1,855	2,453	2,567	2,737	2,948	3,084	3,100	3,122	3,251	4,121	31,431
	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		1,022	1,170	1,855	2,453	2,567	2,737	2,948	3,084	3,100	3,122	3,251	4,121	31,431

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$1,503	$1,280	$39,871	$8,660	$80,520	$12,983	$14,400	$3,000	$29,857	$1,500	$1,500	$1,500	**$196,573**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	317,253	
	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	317,253	
3	Less: Accumulated Depreciation	**0**	0	0	0	0	0	0	0	0	0	0	0	(740)	
4	CWIP - Non-Interest Bearing	**120,680**	122,183	123,463	163,334	171,994	252,513	265,496	279,896	282,896	312,753	314,253	315,753	0	
5	Net Investment (Lines 2 + 3 + 4)	**$120,680**	122,183	123,463	163,334	171,994	252,513	265,496	279,896	282,896	312,753	314,253	315,753	316,513	
6	Average Net Investment		121,432	122,823	143,398	167,664	212,253	259,005	272,696	281,396	297,824	313,503	315,003	316,133	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes **11.16%**		1,129	1,142	1,334	1,559	1,974	2,409	2,536	2,617	2,770	2,916	2,930	2,940	$26,255
	b. Debt Component (Line 6 x 2.57% x 1/12) **2.04%**		206	209	244	285	361	440	464	478	506	533	536	537	4,799
8	Investment Expenses														
	a. Depreciation **5.60%**		0	0	0	0	0	0	0	0	0	0	0	740	740
	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 **0.008160**		0	0	0	0	0	0	0	0	0	0	0	216	216
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,336	1,351	1,577	1,844	2,335	2,849	3,000	3,095	3,276	3,449	3,465	4,433	32,010
	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		1,336	1,351	1,577	1,844	2,335	2,849	3,000	3,095	3,276	3,449	3,465	4,433	32,010

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2007 through December 2007
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$3,315	$1,866	$7,945	$17,300	$27,779	$14,957	$38,267	$19,750	$7,790	$1,500	$1,500	$1,500	**$143,468**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	149,713	
	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	149,713	
3	Less: Accumulated Depreciation	**0**	0	0	0	0	0	0	0	0	0	0	0	(301)	
4	CWIP - Non-Interest Bearing	**6,245**	9,560	11,426	19,370	36,670	64,449	79,406	117,673	137,423	145,213	146,713	148,213	0	
5	Net Investment (Lines 2 + 3 + 4)	**$6,245**	9,560	11,426	19,370	36,670	64,449	79,406	117,673	137,423	145,213	146,713	148,213	149,413	
6	Average Net Investment		7,902	10,493	15,398	28,020	50,560	71,928	98,540	127,548	141,318	145,963	147,463	148,813	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes **11.16%**		73	98	143	261	470	669	916	1,186	1,314	1,357	1,371	1,384	$9,244
	b. Debt Component (Line 6 x 2.57% x 1/12) **2.04%**		13	18	26	48	86	122	168	217	240	248	251	253	1,690
8	Investment Expenses														
	a. Depreciation **4.82%**		0	0	0	0	0	0	0	0	0	0	0	301	301
	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 **0.010864**		0	0	0	0	0	0	0	0	0	0	0	136	136
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		87	115	169	308	556	791	1,084	1,403	1,554	1,606	1,622	2,073	11,370
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		87	115	169	308	556	791	1,084	1,403	1,554	1,606	1,622	2,073	11,370

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Estimated Jul-07	Estimated Aug-07	Estimated Sep-07	Estimated Oct-07	Estimated Nov-07	Estimated Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$1,890	$18,913	$7,205	$8,244	$156,465	$48,680	$40,250	$3,000	$45,774	$1,500	$1,500	$1,500	**$334,921**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	344,257	
	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	344,257	
3	Less: Accumulated Depreciation	**0**	0	0	0	0	0	0	0	0	0	0	0	(615)	
4	CWIP - Non-Interest Bearing	**9,336**	11,226	30,139	37,344	45,588	202,053	250,733	290,983	293,983	339,757	341,257	342,757	0	
5	Net Investment (Lines 2 + 3 + 4)	**$9,336**	11,226	30,139	37,344	45,588	202,053	250,733	290,983	293,983	339,757	341,257	342,757	343,641	
6	Average Net Investment		10,281	20,682	33,741	41,466	123,820	226,393	270,858	292,483	316,870	340,507	342,007	343,199	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes **11.16%**		96	192	314	386	1,152	2,105	2,519	2,720	2,947	3,167	3,181	3,192	$21,969
	b. Debt Component (Line 6 x 2.57% x 1/12) **2.04%**		17	35	57	70	210	385	460	497	539	579	581	583	4,016
8	Investment Expenses														
	a. Depreciation **4.29%**		0	0	0	0	0	0	0	0	0	0	0	615	615
	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 **0.009345**		0	0	0	0	0	0	0	0	0	0	0	268	268
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		113	228	371	456	1,362	2,490	2,979	3,217	3,486	3,746	3,762	4,659	26,869
	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		113	228	371	456	1,362	2,490	2,979	3,217	3,486	3,746	3,762	4,659	26,869

For Project: UNDERGROUND STORAGE TANKS - CRYSTAL RIVER 4 & 5 (Project 10a)
(in Dollars)

Base

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$559	$0	$0	($49,259)	$0	$0	$0	$0	$0	$0	$0	($48,700)
	b. Clearings to Plant		0	0	0	0	0	0	168,941	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	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	(690)	(1,151)	(1,611)	(2,071)	(2,532)	(2,992)	
4	CWIP - Non-Interest Bearing	217,641	217,641	218,200	218,200	218,200	168,941	168,941	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$217,641	217,641	218,200	218,200	218,200	168,941	168,941	168,251	167,791	167,330	166,870	166,410	165,949	
6	Average Net Investment		217,641	217,921	218,200	218,200	193,571	168,941	168,596	168,021	167,561	167,100	166,640	166,179	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxe 11.16%		2,024	2,027	2,029	2,029	1,800	1,571	1,568	1,563	1,558	1,554	1,550	1,545	$20,819
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		370	370	371	371	329	287	287	286	285	284	283	283	3,806
8	Investment Expenses														
	a. Depreciation 3.27%		0	0	0	0	0	0	690	460	460	460	460	460	2,992
	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 0.016338		0	0	0	0	0	0	230	230	230	230	230	230	1,380
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,394	2,397	2,400	2,400	2,129	1,858	2,775	2,539	2,534	2,528	2,523	2,518	28,997
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,394	2,397	2,400	2,400	2,129	1,858	2,775	2,539	2,534	2,528	2,523	2,518	28,997

For Project: UNDERGROUND STORAGE TANKS - BARTOW (Project 10b)
(in Dollars)

Intermediate

Line	Description	Beginning of Period Amount	Actual Jan-07	Actual Feb-07	Actual Mar-07	Actual Apr-07	Actual May-07	Actual Jun-07	Actual Jul-07	Actual Aug-07	Actual Sep-07	Actual Oct-07	Actual Nov-07	Actual Dec-07	End of Period Total
1	Investments														
	a. Expenditures/Additions		$5,635	($3,155)	$0	$0	($21,609)	$599	$0	$0	$0	$0	$0	$0	($18,530)
	b. Clearings to Plant		0	0	0	0	0	75,868	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	75,868	75,868	75,868	75,868	75,868	75,868	75,868	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	(1,109)	(1,310)	(1,512)	(1,714)	(1,915)	(2,117)	(2,319)	
4	CWIP - Non-Interest Bearing	94,398	100,033	96,879	96,879	96,879	75,269	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$94,398	100,033	96,879	96,879	96,879	75,269	74,759	74,558	74,356	74,154	73,953	73,751	73,549	
6	Average Net Investment		97,216	98,456	96,879	96,879	86,074	74,859	74,658	74,457	74,255	74,053	73,852	73,650	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxe 11.16%		904	916	901	901	800	(131)	694	692	691	689	687	685	$8,429
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		165	167	165	165	146	(24)	127	127	126	126	126	125	1,541
8	Investment Expenses														
	a. Depreciation 3.19%		0	0	0	0	0	1,111	202	202	202	202	202	202	2,321
	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 0.009773		0	0	0	0	0	372	62	62	62	62	62	62	743
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,069	1,083	1,066	1,066	947	1,328	1,085	1,082	1,080	1,078	1,076	1,074	13,033
	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		1,069	1,083	1,066	1,066	947	1,328	1,085	1,082	1,080	1,078	1,076	1,074	13,033

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)

Modular Cooling Towers (Project #11)

Modular Cooling Towers - Breakers

Depreciation Rate	0.015932

	12/31/2005
Original Cost	$ 76,876.00
Depreciation	$ 16,075.34
NBV	$ 60,800.66

	Beg NBV	Depreciation	End NBV
December 2005	$ 60,902.73	$ 102.07	$ 60,800.66
January 2006	60,800.66	102.07	60,698.60
February 2006	60,698.60	102.07	60,596.53
March 2006	60,596.53	102.07	60,494.47
April 2006	60,494.47	102.07	60,392.40
May 2006	60,392.40	102.07	60,290.34
June 2006	60,290.34	102.07	60,188.27
July 2006	60,188.27	102.07	60,086.20
August 2006	60,086.20	102.07	59,984.14
September 2006	59,984.14	102.07	59,882.07
October 2006	59,882.07	102.07	59,780.01
November 2006	59,780.01	102.07	59,677.94
December 2006	$ 59,677.94	$ 102.07	$ 59,575.88
13-mth Avg Rate Base			**$ 60,188.27**

	Rates	
Return	13.20%	$ 662.07
Prop Tax	0.01728	$ 86.68
Depreciation	0.015932	$ 102.07
Total Monthly Rev. Req.		$ 850.82
Credit to Project	**9.5 mths**	**$ 8,082.75**

Note: Credit for revenue requirement in rates for the original breakers that were replaced in March 2007 due to increased load from the Modular Cooling Towers. Credit to project in July 2007 is $3,829 which includes true-up for March through June when no credit was applied.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI **EXHIBIT** 37
COMPANY Progress Energy Florida
WITNESS Maritza Jacobo (MI-3)
DATE 11-06-07

Docket 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit ___(MI-3)
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Docket 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit No.__ (MI-4)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1P THROUGH 42-7P

JANUARY 2008 – DECEMBER 2008
Calculation of the Projected Period Amount
January through December 2008
DOCKET NO. 070007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 38
COMPANY Progress Energy Florida
WITNESS Maritza Iacono (MI-4)
DATE 11-06-07

PROGRESS ENERGY FLORIDA

Form 42-1P

Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
JANUARY 2008 - DECEMBER 2008

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)	$15,972,000	$997,434	$15,913,833	$3,635,712	$36,518,979
	b Projected Capital Projects (Form 42-3P, Lines 7 through 9)	4,977,810	0	4,257	1,703,943	6,686,010
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	$20,949,810	$997,434	$15,918,090	$5,339,655	$43,204,989
2	True-up for Estimated Over/(Under) Recovery for the current period January 2007 - December 2007 (Form 42-2E, Line 5 + 6 + 10)	(813,464)	(174,655)	(1,959,621)	(385,788)	($3,333,530)
3	Final True-up for the period January 2006 - December 2006 (Form 42-1A, Line 3)	596,850	179,142	1,257,848	412,874	$2,446,714
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection period January 2008 - December 2008 (Line 1 - Line 2 - Line 3)	$21,166,424	$992,948	$16,619,863	$5,312,570	$44,091,805
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072)	$21,181,664	$993,662	$16,631,830	$5,316,395	$44,123,551

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Form 42-2P

O&M Activities
(in Dollars)

Line	Description	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$120,292	$120,292	$120,292	$120,412	$122,280	$120,412	$114,500	$114,500	$114,500	$116,373	$114,500	$114,500	$1,412,855
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	66,207	66,207	66,207	66,273	67,301	66,273	63,020	63,020	63,020	64,050	63,020	63,020	777,618
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	1,793,822	1,750,207	1,603,265	1,840,826	1,840,725	1,233,939	746,159	746,159	1,112,159	1,038,019	743,919	471,406	14,920,605
	3a Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	44,750	44,750	19,750	19,750	19,750	29,750	39,750	39,750	19,750	19,750	19,750	19,750	337,000
	4 Above Ground Tank Secondary Containment - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	5 SO2 Emissions Allowances	1,440,119	1,261,733	1,306,081	1,330,195	1,074,768	1,558,394	1,651,769	1,679,575	1,639,278	1,298,609	1,029,301	1,291,253	16,561,071
	6 Phase II Cooling Water Intake 316(b) - Base	11,750	0	11,750	10,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	57,500
	6a Phase II Cooling Water Intake 316(b) - Intm	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	90,000
	7.2 CAIR/CAMR - Peaking	48,500	0	0	0	0	0	0	0	0	0	0	0	48,500
	8 Arsenic Groundwater Standard - Base	5,000	5,000	8,053	8,594	8,594	8,594	8,594	8,594	8,594	2,684	2,684	2,684	77,669
	9 Sea Turtle - Coastal Street Lighting - Distrib	23,333	23,333	23,333	23,333	23,333	23,333	23,333	23,333	23,334	23,334	23,334	23,334	280,000
	11a Modular Cooling Towers - Base	0	0	0	0	536,264	834,188	834,188	834,188	297,924	0	0	0	3,336,752
2	Total of O&M Activities	3,561,273	3,279,022	3,166,231	3,426,884	3,703,515	3,885,383	3,491,812	3,519,618	3,289,058	2,573,319	2,007,007	1,996,446	$37,899,569
3	Recoverable Costs Allocated to Energy	1,440,119	1,261,733	1,306,081	1,330,195	1,074,768	1,558,394	1,651,769	1,679,575	1,639,278	1,298,609	1,029,301	1,291,253	16,561,071
4	Recoverable Costs Allocated to Demand - Transm	120,292	120,292	120,292	120,412	122,280	120,412	114,500	114,500	114,500	116,373	114,500	114,500	1,412,855
	Recoverable Costs Allocated to Demand - Distrib	1,883,362	1,839,747	1,692,805	1,930,432	1,931,359	1,323,545	832,512	832,512	1,198,513	1,125,403	830,273	557,760	15,978,223
	Recoverable Costs Allocated to Demand - Prod-Base	16,750	5,000	19,803	18,594	547,858	845,782	845,782	845,782	309,518	5,684	5,684	5,684	3,471,921
	Recoverable Costs Allocated to Demand - Prod-Intm	52,250	52,250	27,250	27,250	27,250	37,250	47,250	47,250	27,250	27,250	27,250	27,250	427,000
	Recoverable Costs Allocated to Demand - Prod-Peaking	48,500	0	0	0	0	0	0	0	0	0	0	0	48,500
5	Retail Energy Jurisdictional Factor	0.96808	0.96495	0.96343	0.96517	0.96637	0.96464	0.96662	0.96470	0.96154	0.95958	0.96089	0.96645	
6	Retail Transmission Demand Jurisdictional Factor	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	0.70597	
	Retail Distribution Demand Jurisdictional Factor	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
	Retail Production Demand Jurisdictional Factor - Base	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
	Retail Production Demand Jurisdictional Factor - Intm	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
	Retail Production Demand Jurisdictional Factor - Peaking	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
7	Jurisdictional Energy Recoverable Costs (A)	1,394,155	1,217,503	1,258,324	1,283,864	1,038,622	1,503,281	1,596,638	1,620,293	1,576,224	1,246,121	989,048	1,247,927	15,972,000
8	Jurisdictional Demand Recoverable Costs - Transm (B)	84,922	84,922	84,922	85,008	86,326	85,008	80,834	80,834	80,834	82,156	80,834	80,834	997,434
	Jurisdictional Demand Recoverable Costs - Distrib (B)	1,875,772	1,832,333	1,685,983	1,922,653	1,923,576	1,318,212	829,157	829,157	1,193,683	1,120,868	826,927	555,512	15,913,833
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	15,704	4,688	18,566	17,432	513,633	792,946	792,946	792,946	290,182	5,329	5,329	5,329	3,255,030
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	41,302	41,302	21,540	21,540	21,540	29,445	37,349	37,349	21,540	21,540	21,540	21,540	337,527
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	43,155	0	0	0	0	0	0	0	0	0	0	0	43,155
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$3,455,010	$3,180,748	$3,069,335	$3,330,497	$3,583,697	$3,728,892	$3,336,924	$3,360,579	$3,162,463	$2,476,014	$1,923,678	$1,911,142	$36,518,979

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

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Form 42-3P

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Description of Investment Projects (A)													
	3b Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$36,023	$36,222	$36,421	$36,620	$36,819	$37,018	$37,192	$37,891	$39,002	$39,976	$40,949	$41,840	$455,973
	4.1 Above Ground Tank Secondary Containment - Peaking	56,901	57,155	57,347	59,724	62,644	65,563	70,137	73,608	77,354	80,825	83,197	84,880	829,335
	4.2 Above Ground Tank Secondary Containment - Base	449	448	612	941	1,286	1,466	1,465	1,464	1,462	1,461	1,460	1,459	13,973
	4.3 Above Ground Tank Secondary Containment - Intermediate	5,693	5,673	5,654	5,634	5,614	5,595	5,575	5,555	5,536	5,516	5,496	5,477	67,018
	5 SO2 Emissions Allowances - Energy	267,267	448,243	483,895	519,171	496,248	472,070	454,414	436,092	417,838	401,680	388,876	376,113	5,161,907
	7.1 CAIR/CAMR - Intermediate	1,597	1,927	2,367	2,862	3,192	3,412	3,632	3,852	4,072	4,402	4,677	4,732	40,724
	7.2 CAIR/CAMR - Peaking	28,056	27,987	27,917	27,848	27,778	27,710	27,641	27,573	27,503	27,434	27,365	27,295	332,107
	7.3 CAIR/CAMR - Base	323	323	323	323	323	323	1,183	3,164	5,144	8,034	17,531	27,474	64,468
	9 Sea Turtle - Coastal Street Lighting -Distribution	259	277	294	312	330	347	365	383	400	418	436	453	4,274
	10.1 Underground Storage Tanks-Base	2,484	2,479	2,474	2,469	2,464	2,459	2,454	2,449	2,444	2,439	2,433	2,428	29,476
	10.2 Underground Storage Tanks-Intermediate	1,069	1,067	1,064	1,062	1,060	1,058	1,056	1,053	1,051	1,049	1,047	1,044	12,680
	11 Modular Cooling Towers - Base	16,149	16,027	15,906	15,784	15,662	15,540	15,419	15,297	15,175	15,053	14,932	14,810	185,756
2	Total Investment Projects - Recoverable Costs	416,270	597,829	634,275	672,750	653,420	632,561	620,533	608,381	596,981	588,287	588,399	588,005	7,197,691
3	Recoverable Costs Allocated to Energy	267,267	448,243	483,895	519,171	496,248	472,070	454,414	436,092	417,838	401,680	388,876	376,113	5,161,907
	Recoverable Costs Allocated to Distribution Demand	259	277	294	312	330	347	365	383	400	418	436	453	4,274
4	Recoverable Costs Allocated to Demand - Production - Base	19,082	18,954	18,992	19,194	19,412	19,465	19,338	19,210	19,081	18,953	18,825	18,697	229,205
	Recoverable Costs Allocated to Demand - Production - Intermediate	44,382	44,889	45,506	46,178	46,685	47,083	47,455	48,351	49,661	50,943	52,169	53,093	576,395
	Recoverable Costs Allocated to Demand - Production - Peaking	84,957	85,142	85,264	87,572	90,422	93,273	97,778	101,181	104,857	108,259	110,562	112,175	1,161,442
5	Retail Energy Jurisdictional Factor	0.96808	0.96495	0.96343	0.96517	0.96637	0.96464	0.96662	0.96470	0.96154	0.95958	0.96089	0.96645	
	Retail Distribution Demand Jurisdictional Factor	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
6	Retail Demand Jurisdictional Factor - Production - Base	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
7	Jurisdictional Energy Recoverable Costs (B)	258,736	432,530	466,202	501,088	479,559	455,375	439,247	420,700	401,766	385,444	373,668	363,493	4,977,810
	Jurisdictional Demand Recoverable Costs (B)	258	276	293	311	329	346	364	381	398	416	434	451	4,257
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	17,890	17,770	17,806	17,995	18,200	18,249	18,130	18,010	17,889	17,769	17,649	17,529	214,887
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	35,082	35,483	35,971	36,502	36,903	37,217	37,511	38,220	39,255	40,268	41,238	41,968	455,617
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	75,594	75,759	75,867	77,921	80,457	82,993	87,002	90,030	93,301	96,328	98,377	99,812	1,033,439
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$387,560	$561,818	$596,138	$633,817	$615,446	$594,181	$582,254	$567,340	$552,609	$540,226	$531,366	$523,254	$6,686,010

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 Projected Period Amount
JANUARY 2008 - DECEMBER 2008

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-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$20,417	$120,417	$95,417	$95,417	$95,417	$80,417	**$657,502**
	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	**$2,698,588**	2,698,588	2,698,588	2,698,588	2,698,588	2,698,588	2,698,588	2,698,588	2,698,588	2,698,588	2,698,588	2,698,588	2,698,588	
3	Less: Accumulated Depreciation	**(254,381)**	(261,285)	(268,189)	(275,093)	(281,997)	(288,901)	(295,805)	(302,709)	(309,612)	(316,516)	(323,420)	(330,324)	(337,228)	
4	CWIP - Non-Interest Bearing	**6,259**	31,259	56,259	81,259	106,259	131,259	156,259	176,676	297,093	392,510	487,927	583,344	663,761	
5	Net Investment (Lines 2 + 3 + 4)	**$2,450,466**	2,468,562	2,486,658	2,504,754	2,522,850	2,540,946	2,559,043	2,572,556	2,686,069	2,774,582	2,863,095	2,951,608	3,025,121	
6	Average Net Investment		2,459,514	2,477,610	2,495,706	2,513,802	2,531,898	2,549,994	2,565,799	2,629,312	2,730,325	2,818,838	2,907,352	2,988,365	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		22,873	23,042	23,210	23,378	23,547	23,715	23,862	24,453	25,392	26,215	27,038	27,792	$294,517
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		4,181	4,212	4,243	4,273	4,304	4,335	4,362	4,470	4,642	4,792	4,942	5,080	53,836
8	Investment Expenses														
	a. Depreciation (C) 3.07%		6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	6,904	82,847
	b. Amortization		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 (D)		2,064	2,064	2,064	2,064	2,064	2,064	2,064	2,064	2,064	2,064	2,064	2,064	24,774
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		36,023	36,222	36,421	36,620	36,819	37,018	37,192	37,891	39,002	39,976	40,949	41,840	455,973
	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		36,023	36,222	36,421	36,620	36,819	37,018	37,192	37,891	39,002	39,976	40,949	41,840	455,973
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)		0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)		28,475	28,632	28,789	28,947	29,104	29,261	29,399	29,951	30,830	31,599	32,369	33,073	360,428
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$28,475	$28,632	$28,789	$28,947	$29,104	$29,261	$29,399	$29,951	$30,830	$31,599	$32,369	$33,073	$360,428

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Lines 2 x 89% @ .009773 x 1/12 + 11%@ .008723 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2005 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - PEAKING (Project 4.1)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$30,000	$35,000	$35,000	$400,000	$150,000	$400,000	$450,000	$200,000	$500,000	$150,000	$300,000	$25,000	**$2,675,000**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	**$3,327,448**	3,327,448	3,327,448	3,327,448	3,327,448	3,327,448	3,327,448	3,327,448	3,327,448	3,327,448	3,327,448	3,327,448	3,327,448	
3	Less: Accumulated Depreciation	**(132,085)**	(141,530)	(150,975)	(160,419)	(169,864)	(179,309)	(188,753)	(198,198)	(207,643)	(217,087)	(226,532)	(235,977)	(245,421)	
4	CWIP - Non-Interest Bearing	**881,723**	911,723	946,723	981,723	1,381,723	1,531,723	1,931,723	2,381,723	2,581,723	3,081,723	3,231,723	3,531,723	3,556,723	
5	Net Investment (Lines 2 + 3 + 4)	**$4,077,086**	4,097,641	4,123,197	4,148,752	4,539,307	4,679,863	5,070,419	5,510,973	5,701,528	6,192,084	6,332,639	6,623,194	6,638,750	
6	Average Net Investment		4,087,363	4,110,419	4,127,994	4,344,029	4,609,585	4,874,867	5,290,697	5,606,251	5,946,806	6,262,362	6,477,916	6,630,972	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		38,012	38,227	38,390	40,399	42,869	45,336	49,203	52,138	55,305	58,240	60,245	61,668	$580,034
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		6,949	6,988	7,018	7,385	7,836	8,287	8,994	9,531	10,110	10,646	11,012	11,273	106,028
8	Investment Expenses														
	a. Depreciation (C)		9,445	9,445	9,445	9,445	9,445	9,445	9,445	9,445	9,445	9,445	9,445	9,445	113,336
	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 (D)		2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	29,946
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		56,901	57,155	57,347	59,724	62,644	65,563	70,137	73,608	77,354	80,825	83,197	84,880	829,345
	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		56,901	57,155	57,347	59,724	62,644	65,563	70,137	73,608	77,354	80,825	83,197	84,880	829,345
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)		0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
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)		50,630	50,856	51,027	53,142	55,740	58,337	62,407	65,496	68,829	71,917	74,028	75,525	737,934
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$50,630	$50,856	$51,027	$53,142	$55,740	$58,337	$62,407	$65,496	$68,829	$71,917	$74,028	$75,525	$737,934

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$30,000	$30,000	$33,000	$0	$0	$0	$0	$0	$0	$0	**$93,000**
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)		**$33,092**	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	
3	Less: Accumulated Depreciation (C)		**(5,883)**	(5,994)	(6,105)	(6,216)	(6,328)	(6,439)	(6,550)	(6,661)	(6,772)	(6,883)	(6,994)	(7,106)	(7,217)	
4	CWIP - Non-Interest Bearing		**0**	0	0	30,000	60,000	93,000	93,000	93,000	93,000	93,000	93,000	93,000	93,000	
5	Net Investment (Lines 2+ 3 + 4)		**$27,209**	27,098	26,987	56,876	86,764	119,653	119,542	119,431	119,320	119,209	119,098	118,986	118,875	
6	Average Net Investment			27,153	27,042	41,931	71,820	103,209	119,598	119,487	119,375	119,264	119,153	119,042	118,931	$0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		253	251	390	668	960	1,112	1,111	1,110	1,109	1,108	1,107	1,106	10,286
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		46	46	71	122	175	203	203	203	203	203	202	202	1,880
8	Investment Expenses															
	a. Depreciation (C)			111	111	111	111	111	111	111	111	111	111	111	111	1,334
	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 (D)			39	39	39	39	39	39	39	39	39	39	39	39	472
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			449	448	612	941	1,286	1,466	1,465	1,464	1,462	1,461	1,460	1,459	13,972
	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			449	448	612	941	1,286	1,466	1,465	1,464	1,462	1,461	1,460	1,459	13,972
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			421	420	574	882	1,206	1,374	1,373	1,373	1,371	1,370	1,369	1,368	13,100
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$421	$420	$574	$882	$1,206	$1,374	$1,373	$1,373	$1,371	$1,370	$1,369	$1,368	$13,100

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)		$ 318,413	318,413	318,413	318,413	318,413	318,413	318,413	318,413	318,413	318,413	318,413	318,413	318,413	
3	Less: Accumulated Depreciation (C)		(2,683)	(4,471)	(6,259)	(8,048)	(9,836)	(11,625)	(13,413)	(15,202)	(16,990)	(18,778)	(20,567)	(22,355)	(24,144)	
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)		$ 315,730	313,942	312,154	310,365	308,577	306,788	305,000	303,211	301,423	299,635	297,846	296,058	294,269	
6	Average Net Investment			314,836	313,048	311,259	309,471	307,682	305,894	304,106	302,317	300,529	298,740	296,952	295,164	0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		2,928	2,911	2,895	2,878	2,861	2,845	2,828	2,812	2,795	2,778	2,762	2,745	34,038
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		535	532	529	526	523	520	517	514	511	508	505	502	6,222
8	Investment Expenses															
	a. Depreciation (C)			1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	21,461
	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 (D)			441	441	441	441	441	441	441	441	441	441	441	441	5,297
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			5,693	5,673	5,654	5,634	5,614	5,595	5,575	5,555	5,536	5,516	5,496	5,477	67,018
	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			5,693	5,673	5,654	5,634	5,614	5,595	5,575	5,555	5,536	5,516	5,496	5,477	67,018
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)			0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)			4,500	4,484	4,469	4,453	4,438	4,423	4,407	4,391	4,376	4,360	4,344	4,329	52,975
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$4,500	$4,484	$4,469	$4,453	$4,438	$4,423	$4,407	$4,391	$4,376	$4,360	$4,344	$4,329	$52,975

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO2 Emission Allowance Inventory		**$2,955,732**	$24,528,945	$23,251,295	$21,929,297	$20,583,185	$18,980,717	$17,304,050	$15,534,008	$13,736,160	$11,978,609	$10,561,727	$9,414,153	$8,004,627	$8,004,627
	b. 25401FL Auctioned SO2 Allowance		**(2,019,940)**	(2,004,023)	(1,988,106)	(1,972,189)	(1,956,272)	(3,191,415)	(3,073,141)	(2,954,868)	(2,836,594)	(2,718,321)	(2,600,047)	(2,481,774)	(2,363,500)	(2,363,500)
	c. 1581002 NOx Emission Allowance Inventory		**6,277,849**	18,855,349	18,855,349	27,905,349	27,905,349	27,905,349	27,905,349	27,905,349	27,905,349	27,905,349	27,905,349	27,905,349	27,905,349	27,905,349
2	Total Working Capital		**$7,213,640**	41,380,270	40,118,537	47,862,456	46,532,261	43,694,651	42,136,257	40,484,489	38,804,914	37,165,637	35,867,028	34,837,728	33,546,475	33,546,475
3	Average Net Investment			24,296,955	40,749,404	43,990,497	47,197,359	45,113,456	42,915,454	41,310,373	39,644,702	37,985,276	36,516,333	35,352,378	34,192,102	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		225,962	378,969	409,112	438,935	419,555	399,114	384,186	368,696	353,263	339,602	328,777	317,987	$4,364,158
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		41,305	69,274	74,784	80,236	76,693	72,956	70,228	67,396	64,575	62,078	60,099	58,127	797,749
5	Total Return Component (B)			267,267	448,243	483,895	519,171	496,248	472,070	454,414	436,092	417,838	401,680	388,876	376,113	5,161,907
6	Expense Dr (Cr)															
	a. 5090001 SO2 allowance expense			1,456,036	1,277,650	1,321,998	1,346,112	1,602,468	1,676,667	1,770,042	1,797,848	1,757,551	1,416,882	1,147,574	1,409,526	17,980,354
	b. 4074004 Amortization Expense			(15,917)	(15,917)	(15,917)	(15,917)	(527,701)	(118,274)	(118,274)	(118,274)	(118,274)	(118,274)	(118,274)	(118,274)	($1,419,283)
7	Net Expense (C)			1,440,119	1,261,733	1,306,081	1,330,195	1,074,768	1,558,394	1,651,769	1,679,575	1,639,278	1,298,609	1,029,301	1,291,253	16,561,071
8	Total System Recoverable Expenses (Lines 5 + 7)			1,707,386	1,709,976	1,789,976	1,849,366	1,571,016	2,030,463	2,106,183	2,115,666	2,057,116	1,700,288	1,418,177	1,667,366	21,722,978
	a. Recoverable costs allocated to Energy			1,707,386	1,709,976	1,789,976	1,849,366	1,571,016	2,030,463	2,106,183	2,115,666	2,057,116	1,700,288	1,418,177	1,667,366	21,722,978
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96808	0.96495	0.96343	0.96517	0.96637	0.96464	0.96662	0.96470	0.96154	0.95958	0.96089	0.96645	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)			1,652,891	1,650,034	1,724,526	1,784,953	1,518,181	1,958,657	2,035,885	2,040,992	1,977,990	1,631,565	1,362,716	1,611,421	20,949,809
12	Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 1,652,891	$ 1,650,034	$ 1,724,526	$ 1,784,953	$ 1,518,181	$ 1,958,657	$ 2,035,885	$ 2,040,992	$ 1,977,990	$ 1,631,565	$ 1,362,716	$ 1,611,421	$ 20,949,809

Notes:
(A) Lines 3 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 Rate Case Settlement in Dkt. 050078-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9.
(E) Line 8b x Line 10.

Docket No. 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit No.___(MI-4)
Page 8 of 29

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Intermediate (Project 7.1 - Anclote Low Nox Burners and SOFA)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$30,000	$30,000	$50,000	$40,000	$20,000	$20,000	$20,000	$20,000	$20,000	$40,000	$10,000	$0	**$300,000**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	**$0**	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	**$0**	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	**130,225**	160,225	190,225	240,225	280,225	300,225	320,225	340,225	360,225	380,225	420,225	430,225	430,225	
5	Net Investment (Lines 2+ 3 + 4)	**130,225**	160,225	190,225	240,225	280,225	300,225	320,225	340,225	360,225	380,225	420,225	430,225	430,225	
6	Average Net Investment		145,225	175,225	215,225	260,225	290,225	310,225	330,225	350,225	370,225	400,225	425,225	430,225	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		1,351	1,630	2,002	2,420	2,699	2,885	3,071	3,257	3,443	3,722	3,955	4,001	$34,435
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		247	298	366	442	493	527	561	595	629	680	723	731	6,295
8	Investment Expenses														
	a. Depreciation (C) 2.21%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.007694		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)		1,597	1,927	2,367	2,862	3,192	3,412	3,632	3,852	4,072	4,402	4,677	4,732	40,730
	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		1,597	1,927	2,367	2,862	3,192	3,412	3,632	3,852	4,072	4,402	4,677	4,732	40,730
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 (Intm)		0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)		1,262	1,523	1,871	2,262	2,523	2,697	2,871	3,045	3,219	3,480	3,697	3,740	32,191
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,262	$1,523	$1,871	$2,262	$2,523	$2,697	$2,871	$3,045	$3,219	$3,480	$3,697	$3,740	$32,191

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

Docket No. 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit No.___(MI-4)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	**$1,857,724**	1,857,723	1,857,723	1,857,723	1,857,723	1,857,723	1,857,723	1,857,723	1,857,723	1,857,723	1,857,723	1,857,723	1,857,723	
3	Less: Accumulated Depreciation	**(3,141)**	(9,424)	(15,707)	(21,990)	(28,273)	(34,556)	(40,838)	(47,121)	(53,404)	(59,687)	(65,970)	(72,253)	(78,535)	
4	CWIP - Non-Interest Bearing	**0**	1	1	1	1	1	1	1	1	1	1	1	1	
5	Net Investment (Lines 2 + 3 + 4)	**$1,854,583**	1,848,300	1,842,018	1,835,735	1,829,452	1,823,169	1,816,886	1,810,603	1,804,321	1,798,038	1,791,755	1,785,472	1,779,189	
6	Average Net Investment		1,851,442	1,845,159	1,838,875	1,832,594	1,826,310	1,820,027	1,813,746	1,807,463	1,801,178	1,794,896	1,788,614	1,782,331	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		17,218	17,160	17,102	17,043	16,985	16,926	16,868	16,809	16,751	16,693	16,634	16,576	$202,765
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		3,147	3,137	3,126	3,115	3,105	3,094	3,083	3,073	3,062	3,051	3,041	3,030	37,064
8	Investment Expenses														
	a. Depreciation (C)		6,283	6,283	6,283	6,283	6,283	6,283	6,283	6,283	6,283	6,283	6,283	6,283	75,394
	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 (D)		1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	16,877
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		28,056	27,987	27,917	27,848	27,778	27,710	27,641	27,573	27,503	27,434	27,365	27,295	332,100
	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		28,056	27,987	27,917	27,848	27,778	27,710	27,641	27,573	27,503	27,434	27,365	27,295	332,100
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)		0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	0.88979	
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)		24,964	24,903	24,840	24,779	24,717	24,656	24,595	24,534	24,472	24,410	24,349	24,287	295,505
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$24,964	$24,903	$24,840	$24,779	$24,717	$24,656	$24,595	$24,534	$24,472	$24,410	$24,349	$24,287	$295,505

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base (Project 7.3 - Continuous Mercury Monitoring Systems)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$156,410	$203,660	$156,410	$369,114	$1,357,645	$450,069	**$2,693,308**
	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		**$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		**29,353**	29,353	29,353	29,353	29,353	29,353	29,353	185,763	389,423	545,833	914,947	2,272,592	2,722,661	
5	Net Investment (Lines 2 + 3 + 4)		**$29,353**	29,353	29,353	29,353	29,353	29,353	29,353	185,763	389,423	545,833	914,947	2,272,592	2,722,661	
6	Average Net Investment			29,353	29,353	29,353	29,353	29,353	29,353	107,558	287,593	467,628	730,390	1,593,770	2,497,627	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		273	273	273	273	273	273	1,000	2,675	4,349	6,793	14,822	23,228	$54,504
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		50	50	50	50	50	50	183	489	795	1,242	2,709	4,246	9,963
8	Investment Expenses															
	a. Depreciation (C)	3.19%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.014268		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)			323	323	323	323	323	323	1,183	3,164	5,144	8,034	17,531	27,474	64,468
	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			323	323	323	323	323	323	1,183	3,164	5,144	8,034	17,531	27,474	64,468
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			303	303	303	303	303	303	1,109	2,966	4,823	7,532	16,436	25,758	60,441
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$303	$303	$303	$303	$303	$303	$1,109	$2,966	$4,823	$7,532	$16,436	$25,758	$60,441

Notes:
(A) Credit reflecting expenses recovered through base rates for breakers that were replaced to compensate for increased load due to the Modular Cooling Towers.
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 5 year life of project, as stated in Dkt. 060162-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 Rate Case Settlement in Dkt. 050078-EI.

Docket No. 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit No. ___ (MI-4)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base - AFUDC (Project 7.4 - Crystal River FGD and SCR)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$54,993,245	$55,543,285	$53,223,543	$48,911,693	$48,655,764	$49,163,131	$50,285,949	$43,831,455	$43,103,444	$42,346,073	$42,186,376	$37,678,046	**$569,922,004**
	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 (B)	8.848%		2,242,149	2,650,473	3,055,413	3,439,687	3,810,473	4,184,785	4,567,541	4,934,087	5,277,738	5,618,556	5,958,538	6,284,362	52,023,802
2	Plant-in-Service/Depreciation Base		**$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-AFUDC Interest Bearing Accrual		**315,671,119**	372,906,513	431,100,271	487,379,227	539,730,607	592,196,844	645,544,760	700,398,250	749,163,792	797,544,974	845,509,603	893,654,517	937,616,925	621,945,806
5	Net Investment (Lines 2 + 3 + 4)		**315,671,119**	372,906,513	431,100,271	487,379,227	539,730,607	592,196,844	645,544,760	700,398,250	749,163,792	797,544,974	845,509,603	893,654,517	937,616,925	
6	Average Net Investment			344,288,816	402,003,392	459,239,749	513,554,917	565,963,725	618,870,802	672,971,505	724,781,021	773,354,383	821,527,288	869,582,060	915,635,721	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	6.82%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.03% x 1/12)	2.03%		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes			0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor			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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
12	Retail Energy-Related Recoverable Costs			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) This schedule shown for informational purposes.
(B) AFUDC calculation based on 2005 Rate Case Settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$1,666	$1,666	$1,666	$1,666	$1,667	$1,667	$1,667	$1,667	$1,667	$1,667	$1,667	$1,667	**$20,000**
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	**$16,035**	16,035	16,035	16,035	16,035	16,035	16,035	16,035	16,035	16,035	16,035	16,035	16,035	
3	Less: Accumulated Depreciation	**(146)**	(208)	(269)	(330)	(392)	(453)	(514)	(576)	(637)	(698)	(760)	(821)	(882)	
4	CWIP - Non-Interest Bearing	**0**	1,666	3,332	4,998	6,664	8,331	9,998	11,665	13,332	14,999	16,666	18,333	20,000	
5	Net Investment (Lines 2 + 3 + 4)	**$15,889**	17,493	19,098	20,703	22,307	23,913	25,519	27,124	28,730	30,336	31,941	33,547	35,153	
6	Average Net Investment		16,691	18,296	19,900	21,505	23,110	24,716	26,321	27,927	29,533	31,138	32,744	34,350	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		155	170	185	200	215	230	245	260	275	290	305	319	$2,848
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		28	31	34	37	39	42	45	47	50	53	56	58	521
8	Investment Expenses														
	a. Depreciation (C) 4.59%		61	61	61	61	61	61	61	61	61	61	61	61	736
	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 (D) 0.010565		14	14	14	14	14	14	14	14	14	14	14	14	169
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		259	277	294	312	330	347	365	383	400	418	436	453	4,274
	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		259	277	294	312	330	347	365	383	400	418	436	453	4,274
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 - (Distribution)		0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	0.99597	
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)		258	276	293	311	329	346	364	381	398	416	434	451	4,257
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$258	$276	$293	$311	$329	$346	$364	$381	$398	$416	$434	$451	$4,257

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - BASE (Project 10.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation		(2,992)	(3,453)	(3,913)	(4,373)	(4,834)	(5,294)	(5,754)	(6,215)	(6,675)	(7,135)	(7,596)	(8,056)	(8,517)	
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)		$165,949	165,489	165,029	164,568	164,108	163,647	163,187	162,727	162,266	161,806	161,346	160,885	160,425	
6	Average Net Investment			165,719	165,259	164,798	164,338	163,878	163,417	162,957	162,497	162,036	161,576	161,115	160,655	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		1,541	1,537	1,533	1,528	1,524	1,520	1,516	1,511	1,507	1,503	1,498	1,494	$18,212
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		282	281	280	279	279	278	277	276	275	275	274	273	3,329
8	Investment Expenses															
	a. Depreciation (C)			460	460	460	460	460	460	460	460	460	460	460	460	5,524
	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 (D)			201	201	201	201	201	201	201	201	201	201	201	201	2,410
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,484	2,479	2,474	2,469	2,464	2,459	2,454	2,449	2,444	2,439	2,433	2,428	29,475
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,484	2,479	2,474	2,469	2,464	2,459	2,454	2,449	2,444	2,439	2,433	2,428	29,475
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)			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			2,329	2,324	2,319	2,315	2,310	2,305	2,301	2,296	2,291	2,287	2,281	2,276	27,635
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,329	$2,324	$2,319	$2,315	$2,310	$2,305	$2,301	$2,296	$2,291	$2,287	$2,281	$2,276	$27,635

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - INTERMEDIATE (10.2)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	**$75,868**	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	
3	Less: Accumulated Depreciation	**(2,319)**	(2,520)	(2,722)	(2,924)	(3,126)	(3,327)	(3,529)	(3,731)	(3,932)	(4,134)	(4,336)	(4,537)	(4,739)	
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)	**$73,549**	73,348	73,146	72,944	72,742	72,541	72,339	72,137	71,936	71,734	71,532	71,331	71,129	
6	Average Net Investment		73,448	73,247	73,045	72,843	72,642	72,440	72,238	72,037	71,835	71,633	71,432	71,230	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		683	681	679	677	676	674	672	670	668	666	664	662	$8,073
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		125	125	124	124	123	123	123	122	122	122	121	121	1,476
8	Investment Expenses														
	a. Depreciation (C)		202	202	202	202	202	202	202	202	202	202	202	202	2,420
	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 (D)		59	59	59	59	59	59	59	59	59	59	59	59	710
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,069	1,067	1,064	1,062	1,060	1,058	1,056	1,053	1,051	1,049	1,047	1,044	12,679
	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		1,069	1,067	1,064	1,062	1,060	1,058	1,056	1,053	1,051	1,049	1,047	1,044	12,679
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)		0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	0.79046	
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)		845	843	841	839	838	836	835	832	831	829	828	825	10,023
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$845	$843	$841	$839	$838	$836	$835	$832	$831	$829	$828	$825	$10,023

Notes:
(A) N/A
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 2005 rates on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Source:
Line 8c Based on 2005 rate case settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2008 - DECEMBER 2008

Return on Capital Investments, Depreciation and Taxes
For Project: MODULAR COOLING TOWERS - BASE (Project 11)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		(851)	(851)	(851)	(851)	(851)	(851)	(851)	(851)	(851)	(851)	(851)	(851)	
2	Plant-in-Service/Depreciation Base	$664,137	664,137	664,137	664,137	664,137	664,137	664,137	664,137	664,137	664,137	664,137	664,137	664,137	
3	Less: Accumulated Depreciation	(191,192)	(202,261)	(213,330)	(224,399)	(235,468)	(246,537)	(257,606)	(268,675)	(279,744)	(290,813)	(301,882)	(312,951)	(324,020)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$472,945	461,876	450,807	439,738	428,669	417,600	406,531	395,462	384,393	373,324	362,255	351,186	340,117	
6	Average Net Investment		467,410	456,341	445,272	434,204	423,135	412,066	400,997	389,928	378,859	367,790	356,721	345,652	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		4,347	4,244	4,141	4,038	3,935	3,832	3,729	3,626	3,523	3,420	3,318	3,215	$45,369
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		795	776	757	738	719	701	682	663	644	625	606	588	8,293
8	Investment Expenses														
	a. Depreciation (C) 20.00%		11,069	11,069	11,069	11,069	11,069	11,069	11,069	11,069	11,069	11,069	11,069	11,069	132,827
	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 (D) 0.014268		790	790	790	790	790	790	790	790	790	790	790	790	9,476
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8) (E)		16,149	16,027	15,906	15,784	15,662	15,540	15,419	15,297	15,175	15,053	14,932	14,810	185,756
	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		16,149	16,027	15,906	15,784	15,662	15,540	15,419	15,297	15,175	15,053	14,932	14,810	185,754
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)		0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)		15,140	15,026	14,912	14,798	14,684	14,569	14,456	14,341	14,227	14,113	13,999	13,885	174,150
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$15,140	$15,026	$14,912	$14,798	$14,684	$14,569	$14,456	$14,341	$14,227	$14,113	$13,999	$13,885	$174,150

Notes:
(A) Credit reflecting expenses recovered through base rates for breakers that were replaced to compensate for increased load due to the Modular Cooling Towers.
(B) Line 6 x 11.16% x 1/12. Based on ROE of 11.75%, weighted cost of equity component of capital structure of 6.85%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 5 year life of project, as stated in Dkt. 060162-EI.
(D) Line 2 x rate x 1/12. Based on 2006 Effective Tax Rate on original cost.
(E) Line 9 - Line 1d.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Source:
Line 8c Based on 2005 Rate Case Settlement in Dkt. 050078-EI.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
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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:
PEF has conducted environmental remediations at 20 substations during 2007. PEF is currently on target to meet the schedule for substation remediations agreed to with the FDEP for 2007.

Project Fiscal Expenditures:
January 1, 2007 to December 31, 2007: Project expenditures are estimated to be $2,276,441 higher than originally projected. This variance is primarily due to higher than expected remediation costs at several substation sites.

Project Progress Summary:
PEF is on schedule according to the approved Substation Inspection Plan and the Substation Assessment and Remedial Action Plan.

Project Projections:
Estimated project expenditures for the period January 2008 through December 2008 are expected to be $2,190,473.

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Description and Progress Report for
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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 conducted environmental inspections on 14,117 sites during 2007. In addition, Progress Energy is expecting to complete remediations on 1,386 distribution padmount transformer sites in 2007. All remediations have been conducted in accordance with the FDEP approved Environmental Remediation Strategy.

Project Fiscal Expenditures:
January 1, 2007 to December 31, 2007: Project expenditures are estimated to be $1,010,677 higher than originally projected. This variance is primarily due to a higher number of sites being remediated than originally anticipated in the 2007 work plan, including carryover from the 2006 work plan.

Project Progress Summary:
This project is on schedule according to the approved Distribution System Investigation, Remediation and Pollution Prevention Program.

Project Projections:
Estimated project expenditures for the period January 2008 through December 2008 are expected to be approximately $15 million. Progress Energy is expecting to conduct approximately 9,300 inspections in 2008 and complete remediations on approximately 1,500 sites.

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Description and Progress Report for
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Project Title: **Pipeline Integrity Management, Review/Update Plan and Risk Assessments**
Project No. 3

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 Integrity 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 requirements for implementing integrity management to operators 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 comply with continual assessment and evaluation of pipeline systems integrity through inspection or testing, data integration and analysis, and follow up with 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, extending 33.3 miles from the Company's Bartow Plant north of St. Petersburg.

Project Accomplishments:
During 2007, PEF continued work on the PIM program. This effort included ongoing activities as required by the integrity management regulation as well as projects to address protection of valve mechanisms along U.S. Highway 19 and remote control of valves designed to isolate sections of the pipeline in the event of a leak.

Project Fiscal Expenditures:
January 1, 2007 to December 31, 2007: O&M project expenditures are estimated to be $511,427 higher than originally projected. This variance is due to carry over work from the 2006 work plan. In addition, $19,741 in capital costs were not incurred because fewer consultant hours were needed for the Pipeline System Control Upgrade project.

Project Progress Summary:
Review and updates to the integrity management plan and risk analyses continue on target. Compliance work will continue through the end of 2007, and into the future.

Project Projections:
Estimated project O&M expenditures for the period January 2008 through December 2008 are expected to be $337,000; estimated capital expenditure for the period are expected to be $657,000.

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Description and Progress Report for
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Project Title: **Above Ground Storage 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 above ground petroleum storage tanks in order to comply with those provisions. Subsection (d) of that rule requires all internally lined single bottom above ground storage tanks to be upgraded with secondary containment, including secondary containment for piping in contact with the soil. Rule 62-761.500(1)(e) also requires that dike field area containment for pre-1998 tanks be upgraded, if needed, to comply with the requirement.

Project Accomplishments:
Activities during 2007 included continued work on above ground storage tank systems at Bayboro, Suwannee, and Anclote.

Project Fiscal Expenditures:
January 1, 2007 to December 31, 2007: Project expenditures will be approximately $536,893 higher than the original projection due to the acceleration of work from 2008 into 2007 on two Anclote storage tanks and unanticipated costs associated with transferring fuel out of tanks to enable work to be performed.

Project Progress Summary:
PEF will continually evaluate its compliance program, including project prioritization, schedule, and technology applications.

Project Projections:
Estimated capital expenditures for the period January 2008 through December 2008 are expected to be approximately $2.8 million. The costs are associated with work at the Debary combustion turbine site and the Crystal River plant.

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Project Title: **SO_2 Emissions Allowances**
Project No. 5

Project Description:
In accordance with Title IV of the Clean Air Act, CFR 40 Part 73 and Florida Statute Regulation 62-214, PEF manages the company's SO2 emissions allowance inventory for the purpose of offsetting sulfur dioxide emissions in compliance with the Federal Acid Rain Program.

Project Accomplishments:
For purposes of compliance with an affected unit's sulfur dioxide emissions requirements under the Acid Rain Program, the air quality compliance costs are administered by an authorized account representative who evaluates a variety of resources and options. Activities performed include purchases, auctions, and transfers of SO2 emissions allowances.

Project Fiscal Expenditures:
January 1, 2007 to December 31, 2007: Project expenditures are estimated to be $2,429,068 lower than originally projected. This variance is primarily driven by a decrease in projected tons of emissions attributable to lower SO2 content in fuel, as well as lower projected energy requirements.

Project Progress Summary:
PEF continually evaluates its compliance strategy to manage the most cost effective program and to mitigate higher gas prices which can impact our fuel mix as it relates to emissions as a result of residual oil.

Project Projections:
Estimated project expenditures for the period January 2008 through December 2008 are expected to be $16,561,071.

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Description and Progress Report for
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Project Title: **Phase II Cooling Water Intake**
Project No. 6

Project Description:
Section 316(b) of the Federal Clean Water Act, requires that "the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." 33 U.S.C. Section 1326. In the past, EPA and the state regulatory agency implemented Section 316(b) on a case-by-case basis. In the new Phase II rules, EPA has established "national performance standards" for determining compliance with Section 316(b) at certain existing electric generating facilities. See 40 CFR 125.94(b). The process of compliance involves planning and scheduling efforts, conducting certain biological studies, and evaluation of options for compliance. These compliance options involve engineering measures, operational measures, restorative measures and/or cost assessment measures. See generally 40 CFR 125.94 and 125.95.

Project Accomplishments:
PEF facilities subject to EPA's new Phase II rules include Anclote, Bartow, Crystal River and Suwannee plants. Early in 2004 PEF requested competitive bids for an environmental consultant to support the development of a Compliance Strategy and Implementation Plan (CSIP); that contract was secured and the CSIP is now complete. The consultant completed a Proposals for Information Collection (PICs) for Anclote and Bartow, Suwannee and Crystal River and they have been submitted to FDEP. FDEP approved all the PICs, and field work is now underway.

Project Fiscal Expenditures:
January 2007 - December 2007: PEF's projected expenditures will be approximately $931,199 less than the original projection for 2007. This variance is primarily attributable to ceasing work and not completing the Comprehensive Demonstration Studies as originally anticipated. This change in approach is due to EPA's official suspension of the 316(b) Phase II rule in the July 9, 2007 Federal Register.

Project Progress Summary:
The original baseline biological studies will be completed. Depending upon ongoing discussions with DEP, additional work associated with the Comprehensive Demonstration Studies (CDS) may be necessary.

Project Projections:
Estimated project O&M expenditures for the period January 2008 through December 2008 are projected to be $147,500 in the event additional CDS work is required.

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Description and Progress Report for
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Project Title: **CAIR and CAMR**
Project No. 7

Project Description:
Clean Air Interstate Rule (CAIR), 40 CFR 24, 262, imposes significant new restrictions on emissions of sulfur dioxide ("SO2") and nitrogen oxides ("NOx") from power plants in 28 eastern states, including Florida and the District of Columbia. The CAIR rule apportions region-wide SO2 and NOx emission reduction requirements to the individual states, and further requires each affected state to revise its State Implementation Plans ("SIP") by September 2006 to include measures necessary to achieve its emission reduction budget within the prescribed deadlines. The Clean Air Mercury Rule (CAMR), 40 CFR Part 60 Subpart Da and 40 CFR Part 60 Subpart HHHH, employs a cap on total mercury emissions from coal-fired power plants in order to achieve significant emissions reductions. Mercury emissions from new and existing coal-fired utility units will be capped at specified nationwide levels.

Project Accomplishments:
Progress Energy has contracted with a team of outside vendors to perform strategy development work. Preliminary engineering work is underway.

Project Fiscal Expenditures:
January 2007 - December 2007: On Crystal River and Anclote projects PEF's expenditures are projected to be approximately $85.3 million higher than originally expected, excluding AFUDC. These costs include preliminary engineering activities and strategy development work necessary to determine the Company's integrated compliance strategy. With the Combustion Turbine projects, costs are projected to be $351,951 higher than originally expected. This variance is due to the acceleration of work from 2008 into the 2007 work plan as well as the carry over of work not being performed in 2006 being completed in 2007.

Project Progress Summary:
PEF will continually evaluate its compliance program, including scheduling and technology applications. With regard to the Crystal River and Anclote plants, the focus is on Crystal River; however, consideration will be given to Anclote in 2008. Combustion turbine projects will complete installation of ports, analyzers and meters and be able to test and certify their systems in 2007.

Project Projections:
Estimated project expenditures for the period January 2008 through December 2008 are expected to be approximately $573 million: CR Units 4 & 5: $570 million; Anclote Unit 1 Nox reduction: $300,000; and Mercury CEMS: $2.7 million.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2008 - DECEMBER 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Arsenic Groundwater Standard**
Project No. 8

Project Description:
On January 22, 2001, the U.S. Environmental Protection Agency (USEPA) adopted a new maximum contaminant level (MCL) for arsenic in drinking water, replacing the previous standard of 0.050 mg/L with a new MCL of 0.010 mg/L (10ppb). Effective January 1, 2005, FDEP established the USEPA MCL as Florida's drinking water standard. See Rule 62-550, F.A.C. The new standard has implications for land application and water reuse projects in Florida because the drinking water standard has been established as the groundwater standard by Rule 62-520.420(1), F.A.C. Lowering the arsenic standard will require new analytical methods for sampling groundwater at numerous PEF sites.

Project Accomplishments:
Sampling of existing monitoring wells continues as required by the groundwater monitoring plan. As results are gathered and submitted to FDEP, PEF will be able to determine future compliance activities and costs. Industrial wastewater permit, including the groundwater monitoring plan, was issued on January 9, 2007.

Project Fiscal Expenditures:
January 2007 - December 2007: O&M costs are expected to be $69,616 lower than originally forecasted as work continues with FDEP to establish an arsenic compliance plan and schedule.

Project Progress Summary:
PEF will continually evaluate analytical results and maintain ongoing communication with FDEP regarding compliance strategies.

Project Projections:
Estimated project expenditures for the period January 2008 through December 2008 are expected to be $77,669 for analytical testing and consultant costs associated with development of compliance strategies. These strategies will depend upon analytical results and discussions with FDEP.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2008 - DECEMBER 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Sea Turtle - Coastal Street Lighting**
Project No. 9

Project Description:
PEF owns and leases high pressure sodium streetlights throughout its service territory, including areas along the Florida coast. Pursuant to Section 161.163, Florida Statutes, the Florida Department of Environmental Protection (FDEP), in collaboration with the Florida Fish and Wildlife Conservation Commission (FFWCC) and the U.S. Fish & Wildlife Service (USFWS), has developed a model Sea Turtle lighting ordinance. The model ordinance is used by the local governments to develop and implement local ordinances within their jurisdiction. To date, Sea Turtle lighting ordinances have been adopted in Franklin County, Gulf County and the City of Mexico Beach in Bay County, all of which are within PEF's service territory. Since 2004, officials from the various local governments, as well as FDEP, FFWC, and USFWS, have advised PEF that lighting it owns and leases is affecting turtle nesting areas that fall within the scope of these ordinances, As a result, the local governments are requiring PEF to take additional measures to satisfy new criteria being applied to ensure compliance with the ordinances.

Project Accomplishments:
PEF has worked with the Franklin County to determine the most cost-effective compliance measures for affected lighting on St. George Island. Compliance measures that have been performed include retrofitting existing streetlights and monitoring to determine the effectiveness of the retrofitted lights. This monitoring is ongoing and is expected to be completed during the second half of this year. Future work is planned for affected lighting in Mexico Beach and additional areas within Franklin County. Project has been delayed pending further studies with the University of Florida.

Project Fiscal Expenditures:
January 1, 2007 to December 31, 2007: Project revenue requirements are estimated to be $394,385 lower than originally projected due to the delay pending further studies.

Project Progress Summary:
PEF is on schedule with the activities identified for this program.

Project Projections:
Estimated project expenditures for the period January 2008 through December 2008 are expected to be $280,000 in O&M costs and $20,000 in capital expenditures to ensure compliance with sea turtle ordinances.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2008 - DECEMBER 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Underground Storage Tanks**
Project No. 10

Project Description:
FDEP rules require that underground pollutant storage tanks and small diameter piping be upgraded with secondary containment by December 31, 2009. See Rule 62-761.510(5), F.A.C. PEF has identified four tanks that must comply with this rule: two at the Crystal River power plant and two at the Bartow power plant. The necessary work was performed in 2006.

Project Accomplishments:
Work on Crystal River and Bartow USTs was completed in the fourth quarter 2006.

Project Fiscal Expenditures:
$0 was projected to be spent in 2007 yet some minimal costs did come through for these projects.

Project Projections:
No project capital expenditures are anticipated for the period January 2008 through December 2008.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2008 - DECEMBER 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Modular Cooling Towers**
Project No. 11

Project Description:
The project involves installation and operation of modular cooling towers in the summer months to minimize "de-rates" of PEF's Cyrstal River Units 1 and 2 necessary to comply with the NPDES permit limit for the temperature of cooling water discharged from the units.

Project Accomplishments:
Vendors of modular cooling towers were evaluated regarding cost of installation and operation. The Florida Department of Environmental Protection reviewed the project and approved operation. A vendor was selected and the towers were installed during the second quarter of 2006.

Project Fiscal Expenditures:
Project O&M costs of approximately $3.4 million per year are expected, including unit mobilization and setup, rental fees, de-mobilization and fill replacement.

Project Progress Summary:
Modular cooling towers began operation in June 2006 and have successfully minimized de-rates of Units 1 and 2.

Project Projections:
Estimated project expenditures are expected to be approximately $3.4 million for the period January 2008 thru December 2008.

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)

Calculation of the Energy & Demand Allocation % by Rate Class

January - December 2008

Form 42-6P

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Sales at Meter (mWh)	(3) Avg 12 CP at Meter (MW) (2)/(8760hrsx(1))	(4) NCP Class Max Load Factor	(5) Delivery Efficiency Factor	(6) Sales at Source (Generation) (mWh) (2)/(5)	(7) Avg 12 CP at Source (MW) (3)/(5)	7(a) Sales at Source (Distrib Svc Only) (mWh)	(8) Class Max MW at Source Level (Distrib Svc) (7a)/(8760hrs/(4))	(9) mWh Sales at Source Energy Allocator (%)	(10) 12CP Demand Transmission Allocator (%)	(11) **12CP & 1/13 AD** Demand Allocator (%)	(12) NCP Distribution Allocator (%)
Residential													
RS-1, RST-1, RSL-1, RSL-2, RSS-1	1												
Secondary	0.550	21,431,535	4,448.22	0.395	0.9384179	22,837,944	4,740.13	22,837,944	6,600.2	51.727%	61.181%	60.454%	63.745%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.658	1,391,472	241.40	0.453	0.9384179	1,482,785	257.25	1,482,785	373.7	3.358%	3.320%	3.323%	3.609%
Primary	0.658	8,958	1.55	0.453	0.9668000	9,266	1.61	9,266	2.3	0.021%	0.021%	0.021%	0.023%
Transmission	0.658	3,707	0.64	0.453	0.9768000	3,795	0.66	0	0.0	0.009%	0.008%	0.009%	0.000%
										3.388%	3.350%	3.352%	3.631%
General Service													
GS-2 Secondary	1.000	89,286	10.19	1.000	0.9384179	95,145	10.86	95,145	10.9	0.216%	0.140%	0.146%	0.105%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.789	12,946,646	1,873.17	0.634	0.9384179	13,796,248	1,996.09	13,796,248	2,484.1	31.248%	25.764%	26.185%	23.992%
Primary	0.789	2,465,111	356.66	0.634	0.9668000	2,549,763	368.91	2,549,763	459.1	5.775%	4.762%	4.839%	4.434%
Transmission	0.789	0	0.00	0.634	0.9768000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
SS-1 Primary	1.264	0	0.00	0.173	0.9668000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	1.264	10,208	0.92	0.173	0.9768000	10,450	0.94	0	0.0	0.024%	0.012%	0.013%	0.000%
Transm Del/ Primary Mtr	1.264	3,388	0.31	0.173	0.9668000	3,504	0.32	0	0.0	0.008%	0.004%	0.004%	0.000%
										37.055%	30.541%	31.042%	28.426%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	1.093	0	0.00	0.720	0.9384179	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Primary	1.093	193,300	20.19	0.720	0.9668000	199,938	20.88	199,938	31.7	0.453%	0.270%	0.284%	0.306%
SS-3 Primary	∞	2,146	0.00	0.047	0.9668000	2,220	0.00	2,220	5.4	0.005%	0.000%	0.000%	0.052%
										0.458%	0.270%	0.284%	0.358%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.927	120,638	14.86	0.710	0.9384179	128,555	15.83	128,555	20.7	0.291%	0.204%	0.211%	0.200%
Primary Del / Primary Mtr	0.927	1,653,559	203.63	0.710	0.9668000	1,710,342	210.62	1,710,342	275.0	3.874%	2.718%	2.807%	2.656%
Primary Del / Transm Mtr	0.927	2,884	0.36	0.710	0.9768000	2,952	0.36	2,952	0.5	0.007%	0.005%	0.005%	0.005%
Transm Del/ Transm Mtr	0.927	457,736	56.37	0.710	0.9768000	468,608	57.71	0	0.0	1.061%	0.745%	0.769%	0.000%
Transm Del/ Primary Mtr	0.927	410,751	50.58	0.710	0.9668000	424,856	52.32	0	0.0	0.962%	0.675%	0.697%	0.000%
SS-2 Primary	0.749	0	0.00	0.263	0.9668000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.749	10,516	1.60	0.263	0.9768000	10,766	1.64	0	0.0	0.024%	0.021%	0.021%	0.000%
Transm Del/ Primary Mtr	0.749	32,837	5.00	0.263	0.9668000	33,965	5.18	0	0.0	0.077%	0.067%	0.068%	0.000%
										6.297%	4.436%	4.579%	2.860%
Lighting													
LS-1 (Secondary)	6.746	356,390	6.03	0.479	0.9384179	379,777	6.43	379,777	90.5	0.860%	0.083%	0.143%	0.874%
		41,591,068	7,291.69			44,150,879	7,747.73	43,194,935	10,354.0	100.000%	100.000%	100.000%	100.000%
								(0)					

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2006
(2) Projected kWh sales for the period January 2007 to December 2007
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2006
(5) Based on system average line loss analysis for 2005
(6) Column 2 / Column 5
(7) Column 3 / Column 5
(7a) Column 6 excluding transmission service
(8) Calculated: Column 7a / (8,760 hours/ Column 4)
(9) Column 6/ Total Column 6
(10) Column 7/ Total Column 7
(11) Column 9 x 1/13 + Column 10 x 12/13
(12) Column 8/ Total Column 8

PROGRESS ENERGY FLORIDA

Form 42-7P

Environmental Cost Recovery Clause (ECRC)

Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class

JANUARY 2008 - DECEMBER 2008

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	51.727%	61.181%	60.454%	63.745%	$10,956,648	$607,932	$10,602,035	$3,213,957	$25,380,572	21,431,535	**0.118**
General Service Non-Demand											
GS-1, GST-1											
Secondary										1,391,472	**0.109**
Primary										8,868	**0.108**
Transmission										3,633	**0.107**
TOTAL GS	3.388%	3.350%	3.352%	3.631%	$717,641	$33,283	$603,969	$178,231	$1,533,125	**1,403,973**	
General Service											
GS-2 Secondary	0.216%	0.140%	0.146%	0.105%	$45,647	$1,393	$17,447	$7,761	$72,247	89,286	**0.081**
General Service Demand											
GSD-1, GSDT-1, SS-1											
Secondary										12,946,646	**0.094**
Primary										2,443,814	**0.093**
Transmission										10,004	**0.092**
TOTAL GSD	37.055%	30.541%	31.042%	28.426%	$7,848,797	$303,478	$4,727,721	$1,650,334	$14,530,330	***15,400,464***	
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										-	**0.090**
Primary										193,492	**0.089**
Transmission										-	**0.088**
TOTAL CS	0.458%	0.270%	0.284%	0.358%	$96,986	$2,678	$59,581	$15,099	$174,344	**193,492**	
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
Secondary										120,638	**0.079**
Primary										2,076,176	**0.078**
Transmission										461,713	**0.077**
TOTAL IS	6.297%	4.436%	4.579%	2.860%	$1,333,744	$44,075	$475,691	$243,424	$2,096,934	**2,658,527**	
Lighting											
LS-1 Secondary	0.860%	0.083%	0.143%	0.874%	$182,201	$824	$145,386	$7,588	$335,999	356,390	**0.094**
	100.000%	100.000%	100.000%	100.000%	$21,181,664	$993,662	$16,631,830	$5,316,395	$44,123,551	41,533,666	**0.106**

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 2007 to December 2007
(11) Column 7/ Column 8 x 100

Docket 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit No.__ (MI-5)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
CAPITAL PROGRAM DETAIL

JANUARY 2008 – DECEMBER 2008
Calculation of the Projected Period Amount
January through December 2008
DOCKET NO. 070007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 39
COMPANY Progress Energy Florida
WITNESS Maritza Iacona (MI-5)
DATE 11-06-07

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$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	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	
5	Net Investment (Lines 2 + 3 + 4)	$673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	
6	Average Net Investment		673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	673,740	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	6,266	$75,189
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	13,744
8	Investment Expenses														
	a. Depreciation 1.86%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.009156		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)		7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	88,934
	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		7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	7,411	88,934

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	153,698	
3	Less: Accumulated Depreciation	(25,508)	(25,932)	(26,356)	(26,779)	(27,203)	(27,627)	(28,051)	(28,475)	(28,899)	(29,323)	(29,747)	(30,171)	(30,595)	
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)	$128,190	127,766	127,342	126,919	126,495	126,071	125,647	125,223	124,799	124,375	123,951	123,527	123,103	
6	Average Net Investment		127,978	127,554	127,131	126,707	126,283	125,859	125,435	125,011	124,587	124,163	123,739	123,315	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,190	1,186	1,182	1,178	1,174	1,170	1,167	1,163	1,159	1,155	1,151	1,147	$14,022
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		218	217	216	215	215	214	213	213	212	211	210	210	2,563
8	Investment Expenses														
	a. Depreciation 3.31%		424	424	424	424	424	424	424	424	424	424	424	424	5,087
	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 0.009364		120	120	120	120	120	120	120	120	120	120	120	120	1,439
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,952	1,947	1,942	1,938	1,933	1,928	1,924	1,919	1,914	1,910	1,905	1,900	23,111
	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		1,952	1,947	1,942	1,938	1,933	1,928	1,924	1,919	1,914	1,910	1,905	1,900	23,111

Docket No. 070007-EI
Progress Energy Florida
Witness: M. Iacono
Exhibit No. ___ (MI-5)
Page 1 of 10

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER (Project 4.2)
(in Dollars)

Base

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$30,000	$30,000	$33,000	$0	$0	$0	$0	$0	$0	$0	$93,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	
3	Less: Accumulated Depreciation	(5,883)	(5,994)	(6,105)	(6,216)	(6,328)	(6,439)	(6,550)	(6,661)	(6,772)	(6,883)	(6,994)	(7,106)	(7,217)	
4	CWIP - Non-Interest Bearing	0	0	0	30,000	60,000	93,000	93,000	93,000	93,000	93,000	93,000	93,000	93,000	
5	Net Investment (Lines 2 + 3 + 4)	$27,209	27,098	26,987	56,876	86,764	119,653	119,542	119,431	119,320	119,209	119,098	118,986	118,875	
6	Average Net Investment		27,153	27,042	41,931	71,820	103,209	119,598	119,487	119,375	119,264	119,153	119,042	118,931	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		253	251	390	668	960	1,112	1,111	1,110	1,109	1,108	1,107	1,106	$10,286
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		46	46	71	122	175	203	203	203	203	203	202	202	1,880
8	Investment Expenses														
	a. Depreciation 4.03%		111	111	111	111	111	111	111	111	111	111	111	111	1,334
	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 0.014268		39	39	39	39	39	39	39	39	39	39	39	39	472
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		449	448	612	941	1,286	1,466	1,465	1,464	1,462	1,461	1,460	1,459	13,972
	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		449	448	612	941	1,286	1,466	1,465	1,464	1,462	1,461	1,460	1,459	13,972

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	1,614,230	
3	Less: Accumulated Depreciation	(61,562)	(66,122)	(70,682)	(75,243)	(79,803)	(84,363)	(88,923)	(93,483)	(98,044)	(102,604)	(107,164)	(111,724)	(116,284)	
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)	$1,552,668	1,548,108	1,543,548	1,538,988	1,534,427	1,529,867	1,525,307	1,520,747	1,516,187	1,511,626	1,507,066	1,502,506	1,497,946	
6	Average Net Investment		1,550,388	1,545,828	1,533,288	1,536,707	1,532,147	1,527,587	1,523,027	1,518,467	1,513,906	1,509,346	1,504,786	1,500,226	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		14,419	14,376	14,260	14,291	14,249	14,207	14,164	14,122	14,079	14,037	13,995	13,952	$170,150
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		2,636	2,628	2,607	2,612	2,605	2,597	2,589	2,581	2,574	2,566	2,558	2,550	31,103
8	Investment Expenses														
	a. Depreciation 3.39%		4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	4,560	54,722
	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 0.008151		1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	13,158
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		22,711	22,661	22,523	22,560	22,510	22,460	22,410	22,360	22,310	22,259	22,209	22,159	269,133
	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		22,711	22,661	22,523	22,560	22,510	22,460	22,410	22,360	22,310	22,259	22,209	22,159	269,133

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	
3	Less: Accumulated Depreciation	(8,681)	(9,202)	(9,722)	(10,243)	(10,763)	(11,283)	(11,804)	(12,324)	(12,845)	(13,365)	(13,886)	(14,406)	(14,926)	
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)	$170,257	169,736	169,216	168,695	168,175	167,654	167,134	166,614	166,093	165,573	165,052	164,532	164,012	
6	Average Net Investment		169,996	169,476	168,955	168,435	167,915	167,394	166,874	166,353	165,833	165,313	164,792	164,272	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,581	1,576	1,571	1,566	1,562	1,557	1,552	1,547	1,542	1,537	1,533	1,528	$18,652
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		289	288	287	286	285	285	284	283	282	281	280	279	3,410
8	Investment Expenses														
	a. Depreciation 3.49%		520	520	520	520	520	520	520	520	520	520	520	520	6,245
	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 0.009716		145	145	145	145	145	145	145	145	145	145	145	145	1,739
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,535	2,530	2,524	2,518	2,512	2,507	2,501	2,495	2,489	2,484	2,478	2,472	30,045
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,535	2,530	2,524	2,518	2,512	2,507	2,501	2,495	2,489	2,484	2,478	2,472	30,045

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$352,593	352,593	352,593	352,593	352,593	352,593	352,593	352,593	352,593	352,593	352,593	352,593	352,593	
3	Less: Accumulated Depreciation	(7,425)	(8,207)	(8,988)	(9,770)	(10,552)	(11,333)	(12,115)	(12,896)	(13,678)	(14,459)	(15,241)	(16,023)	(16,804)	
4	CWIP - Non-Interest Bearing	207,400	207,400	207,400	207,400	207,400	207,400	207,400	207,400	207,400	207,400	207,400	207,400	207,400	
5	Net Investment (Lines 2 + 3 + 4)	$552,567	551,786	551,004	550,223	549,441	548,660	547,879	547,096	546,315	545,533	544,752	543,970	543,188	
6	Average Net Investment		552,177	551,395	550,613	549,832	549,050	547,996	547,488	546,706	545,924	545,142	544,361	543,579	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		5,135	5,128	5,121	5,113	5,106	5,096	5,092	5,084	5,077	5,070	5,063	5,055	$61,141
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		939	937	936	935	933	932	931	929	928	927	925	924	11,176
8	Investment Expenses														
	a. Depreciation 2.66%		782	782	782	782	782	782	782	782	782	782	782	782	9,379
	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 0.009364		275	275	275	275	275	275	275	275	275	275	275	275	3,302
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		7,131	7,122	7,113	7,105	7,096	7,085	7,079	7,070	7,062	7,053	7,045	7,036	84,998
	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		7,131	7,122	7,113	7,105	7,096	7,085	7,079	7,070	7,062	7,053	7,045	7,036	84,998

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$886,554	886,554	886,554	886,554	886,554	886,554	886,554	886,554	886,554	886,554	886,554	886,554	886,554	
3	Less: Accumulated Depreciation	(10,639)	(13,003)	(15,367)	(17,731)	(20,095)	(22,459)	(24,824)	(27,188)	(29,552)	(31,916)	(34,280)	(36,644)	(39,008)	
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)	$875,915	873,551	871,187	868,823	866,458	864,094	861,730	859,366	857,002	854,638	852,274	849,909	847,545	
6	Average Net Investment		874,733	872,369	870,005	867,640	865,276	862,912	860,548	858,184	855,820	853,456	851,091	848,727	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		8,135	8,113	8,091	8,069	8,047	8,025	8,003	7,981	7,959	7,937	7,915	7,893	$96,169
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		1,487	1,483	1,479	1,475	1,471	1,467	1,463	1,459	1,455	1,451	1,447	1,443	17,579
8	Investment Expenses														
	a. Depreciation 3.20%		2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	28,370
	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 0.008974		663	663	663	663	663	663	663	663	663	663	663	663	7,956
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		12,649	12,623	12,597	12,571	12,545	12,519	12,493	12,467	12,441	12,415	12,389	12,363	150,074
	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		12,649	12,623	12,597	12,571	12,545	12,519	12,493	12,467	12,441	12,415	12,389	12,363	150,074

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$30,000	$35,000	$35,000	$400,000	$150,000	$400,000	$450,000	$200,000	$500,000	$150,000	$300,000	$25,000	$2,675,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$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	584	30,584	65,584	100,584	500,584	650,584	1,050,584	1,500,584	1,700,584	2,200,584	2,350,584	2,650,584	2,675,584	
5	Net Investment (Lines 2 + 3 + 4)	$584	30,584	65,584	100,584	500,584	650,584	1,050,584	1,500,584	1,700,584	2,200,584	2,350,584	2,650,584	2,675,584	
6	Average Net Investment		15,584	48,084	83,084	300,584	575,584	850,584	1,275,584	1,600,584	1,950,584	2,275,584	2,500,584	2,663,084	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		145	447	773	2,795	5,353	7,910	11,863	14,885	18,140	21,163	23,255	24,767	$131,497
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		26	82	141	511	978	1,446	2,168	2,721	3,316	3,868	4,251	4,527	24,037
8	Investment Expenses														
	a. Depreciation 2.33%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.009156		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)		171	529	914	3,306	6,331	9,356	14,031	17,606	21,456	25,031	27,506	29,294	155,535
	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		171	529	914	3,306	6,331	9,356	14,031	17,606	21,456	25,031	27,506	29,294	155,535

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Peaking

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	
3	Less: Accumulated Depreciation	(18,270)	(19,065)	(19,859)	(20,653)	(21,448)	(22,242)	(23,037)	(23,831)	(24,625)	(25,420)	(26,214)	(27,009)	(27,803)	
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)	$123,164	122,370	121,576	120,781	119,987	119,192	118,398	117,604	116,809	116,015	115,220	114,426	113,632	
6	Average Net Investment		122,767	121,973	121,178	120,384	119,590	118,795	118,001	117,206	116,412	115,618	114,823	114,029	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,142	1,134	1,127	1,120	1,112	1,105	1,097	1,090	1,083	1,075	1,068	1,060	$13,213
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		209	207	206	205	203	202	201	199	198	197	195	194	2,415
8	Investment Expenses														
	a. Depreciation 6.74%		794	794	794	794	794	794	794	794	794	794	794	794	9,533
	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 0.016637		196	196	196	196	196	196	196	196	196	196	196	196	2,353
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,341	2,332	2,323	2,315	2,306	2,297	2,288	2,280	2,271	2,262	2,254	2,245	27,514
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,341	2,332	2,323	2,315	2,306	2,297	2,288	2,280	2,271	2,262	2,254	2,245	27,514

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Intermediate

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$318,413	318,413	318,413	318,413	318,413	318,413	318,413	318,413	318,413	318,413	318,413	318,413	318,413	
3	Less: Accumulated Depreciation	(2,683)	(4,471)	(6,259)	(8,048)	(9,836)	(11,625)	(13,413)	(15,202)	(16,990)	(18,778)	(20,567)	(22,355)	(24,144)	
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)	$315,730	313,942	312,154	310,365	308,577	306,788	305,000	303,211	301,423	299,635	297,846	296,058	294,269	
6	Average Net Investment		314,836	313,048	311,259	309,471	307,682	305,894	304,106	302,317	300,529	298,740	296,952	295,164	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		2,928	2,911	2,895	2,878	2,861	2,845	2,828	2,812	2,795	2,778	2,762	2,745	$34,038
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		535	532	529	526	523	520	517	514	511	508	505	502	6,222
8	Investment Expenses														
	a. Depreciation 3.34%		1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	1,788	21,461
	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 0.007694		441	441	441	441	441	441	441	441	441	441	441	441	5,297
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		5,693	5,673	5,654	5,634	5,614	5,595	5,575	5,555	5,536	5,516	5,496	5,477	67,018
	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		5,693	5,673	5,654	5,634	5,614	5,595	5,575	5,555	5,536	5,516	5,496	5,477	67,018

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

ALL Peaking

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$161,334	161,334	161,334	161,334	161,334	161,334	161,334	161,334	161,334	161,334	161,334	161,334	161,334	
3	Less: Accumulated Depreciation	(121)	(363)	(605)	(847)	(1,089)	(1,331)	(1,573)	(1,815)	(2,057)	(2,299)	(2,541)	(2,783)	(3,025)	
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)	$161,213	160,971	160,729	160,487	160,245	160,003	159,761	159,519	159,277	159,035	158,793	158,551	158,309	
6	Average Net Investment		161,092	160,850	160,608	160,366	160,124	159,882	159,640	159,398	159,156	158,914	158,672	158,430	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,498	1,496	1,494	1,491	1,489	1,487	1,485	1,482	1,480	1,478	1,476	1,473	$17,829
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		274	273	273	273	272	272	271	271	271	270	270	269	3,259
8	Investment Expenses														
	a. Depreciation 1.80%		242	242	242	242	242	242	242	242	242	242	242	242	2,904
	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 0.009716		131	131	131	131	131	131	131	131	131	131	131	131	1,568
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,145	2,142	2,139	2,137	2,134	2,131	2,129	2,126	2,123	2,121	2,118	2,115	25,560
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,145	2,142	2,139	2,137	2,134	2,131	2,129	2,126	2,123	2,121	2,118	2,115	25,560

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$268,824	268,824	268,824	268,824	268,824	268,824	268,824	268,824	268,824	268,824	268,824	268,824	268,824	
3	Less: Accumulated Depreciation	(479)	(1,438)	(2,397)	(3,356)	(4,315)	(5,273)	(6,232)	(7,191)	(8,150)	(9,109)	(10,067)	(11,026)	(11,985)	
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)	$268,344	267,385	266,426	265,468	264,509	263,550	262,591	261,632	260,674	259,715	258,756	257,797	256,838	
6	Average Net Investment		267,865	266,906	265,947	264,988	264,029	263,071	262,112	261,153	260,194	259,235	258,277	257,318	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		2,491	2,482	2,473	2,464	2,455	2,447	2,438	2,429	2,420	2,411	2,402	2,393	$29,305
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		455	454	452	450	449	447	446	444	442	441	439	437	5,357
8	Investment Expenses														
	a. Depreciation 4.28%		959	959	959	959	959	959	959	959	959	959	959	959	11,506
	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 0.009364		210	210	210	210	210	210	210	210	210	210	210	210	2,517
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,115	4,105	4,094	4,083	4,073	4,062	4,052	4,041	4,031	4,020	4,010	3,999	48,685
	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		4,115	4,105	4,094	4,083	4,073	4,062	4,052	4,041	4,031	4,020	4,010	3,999	48,685

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$187,110	187,110	187,110	187,110	187,110	187,110	187,110	187,110	187,110	187,110	187,110	187,110	187,110	
3	Less: Accumulated Depreciation	(234)	(702)	(1,169)	(1,637)	(2,105)	(2,573)	(3,041)	(3,508)	(3,976)	(4,444)	(4,912)	(5,379)	(5,847)	
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)	$186,876	186,408	185,941	185,473	185,005	184,537	184,069	183,602	183,134	182,666	182,198	181,731	181,263	
6	Average Net Investment		186,642	186,174	185,707	185,239	184,771	184,303	183,836	183,368	182,900	182,432	181,964	181,497	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,736	1,731	1,727	1,723	1,718	1,714	1,710	1,705	1,701	1,697	1,692	1,688	$20,542
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		317	316	316	315	314	313	313	312	311	310	309	309	3,755
8	Investment Expenses														
	a. Depreciation 3.00%		468	468	468	468	468	468	468	468	468	468	468	468	5,613
	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 0.009364		146	146	146	146	146	146	146	146	146	146	146	146	1,752
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,667	2,662	2,657	2,651	2,646	2,641	2,636	2,631	2,626	2,621	2,615	2,610	31,663
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,667	2,662	2,657	2,651	2,646	2,641	2,636	2,631	2,626	2,621	2,615	2,610	31,663

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$121,748	121,748	121,748	121,748	121,748	121,748	121,748	121,748	121,748	121,748	121,748	121,748	121,748	
3	Less: Accumulated Depreciation	(151)	(454)	(756)	(1,058)	(1,361)	(1,663)	(1,965)	(2,268)	(2,570)	(2,872)	(3,175)	(3,477)	(3,779)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$121,597	121,294	120,992	120,690	120,387	120,085	119,783	119,480	119,178	118,876	118,573	118,271	117,969	
6	Average Net Investment		121,446	121,143	120,841	120,539	120,236	119,934	119,632	119,329	119,027	118,725	118,422	118,120	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,129	1,127	1,124	1,121	1,118	1,115	1,113	1,110	1,107	1,104	1,101	1,099	$13,368
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		206	206	205	205	204	204	203	203	202	202	201	201	2,444
8	Investment Expenses														
	a. Depreciation 2.98%		302	302	302	302	302	302	302	302	302	302	302	302	3,628
	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 0.009156		93	93	93	93	93	93	93	93	93	93	93	93	1,115
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,731	1,728	1,724	1,721	1,718	1,715	1,711	1,708	1,705	1,701	1,698	1,695	20,554
	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		1,731	1,728	1,724	1,721	1,718	1,715	1,711	1,708	1,705	1,701	1,698	1,695	20,554

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2008 through December 2008
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$307,486	307,486	307,486	307,486	307,486	307,486	307,486	307,486	307,486	307,486	307,486	307,486	307,486	
3	Less: Accumulated Depreciation	(500)	(1,499)	(2,498)	(3,498)	(4,497)	(5,496)	(6,496)	(7,495)	(8,494)	(9,494)	(10,493)	(11,492)	(12,492)	
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)	$306,987	305,987	304,988	303,989	302,989	301,990	300,991	299,991	298,992	297,993	296,993	295,994	294,995	
6	Average Net Investment		306,487	305,488	304,488	303,489	302,490	301,490	300,491	299,492	298,492	297,493	296,494	295,494	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		2,850	2,841	2,832	2,822	2,813	2,804	2,795	2,785	2,776	2,767	2,757	2,748	$33,591
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		521	519	518	516	514	513	511	509	507	506	504	502	6,140
8	Investment Expenses														
	a. Depreciation 3.90%		999	999	999	999	999	999	999	999	999	999	999	999	11,992
	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 0.009364		240	240	240	240	240	240	240	240	240	240	240	240	2,879
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,611	4,600	4,589	4,578	4,567	4,556	4,545	4,534	4,523	4,512	4,501	4,490	54,602
	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		4,611	4,600	4,589	4,578	4,567	4,556	4,545	4,534	4,523	4,512	4,501	4,490	54,602

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$317,253	317,253	317,253	317,253	317,253	317,253	317,253	317,253	317,253	317,253	317,253	317,253	317,253	
3	Less: Accumulated Depreciation	(740)	(2,221)	(3,701)	(5,182)	(6,662)	(8,143)	(9,623)	(11,104)	(12,584)	(14,065)	(15,545)	(17,026)	(18,506)	
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)	$316,513	315,032	313,552	312,071	310,591	309,110	307,630	306,149	304,669	303,188	301,708	300,227	298,747	
6	Average Net Investment		315,772	314,292	312,811	311,331	309,850	308,370	306,889	305,409	303,928	302,448	300,967	299,487	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		2,937	2,923	2,909	2,895	2,882	2,868	2,854	2,840	2,827	2,813	2,799	2,785	$34,331
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		537	534	532	529	527	524	522	519	517	514	512	509	6,276
8	Investment Expenses														
	a. Depreciation 5.60%		1,481	1,481	1,481	1,481	1,481	1,481	1,481	1,481	1,481	1,481	1,481	1,481	17,766
	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 0.008151		215	215	215	215	215	215	215	215	215	215	215	215	2,586
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		5,170	5,153	5,137	5,121	5,104	5,088	5,072	5,056	5,039	5,023	5,007	4,990	60,959
	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		5,170	5,153	5,137	5,121	5,104	5,088	5,072	5,056	5,039	5,023	5,007	4,990	60,959

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$149,713	149,713	149,713	149,713	149,713	149,713	149,713	149,713	149,713	149,713	149,713	149,713	149,713	
3	Less: Accumulated Depreciation	(301)	(902)	(1,503)	(2,105)	(2,706)	(3,307)	(3,909)	(4,510)	(5,111)	(5,713)	(6,314)	(6,915)	(7,517)	
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)	$149,413	148,811	148,210	147,609	147,007	146,406	145,805	145,203	144,602	144,001	143,399	142,798	142,197	
6	Average Net Investment		149,112	148,511	147,909	147,308	146,707	146,105	145,504	144,903	144,301	143,700	143,099	142,497	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,387	1,381	1,376	1,370	1,364	1,359	1,353	1,348	1,342	1,336	1,331	1,325	$16,272
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		253	252	251	250	249	248	247	246	245	244	243	242	2,974
8	Investment Expenses														
	a. Depreciation 4.82%		601	601	601	601	601	601	601	601	601	601	601	601	7,216
	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 0.009156		114	114	114	114	114	114	114	114	114	114	114	114	1,371
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,356	2,349	2,343	2,336	2,329	2,323	2,316	2,310	2,303	2,296	2,290	2,283	27,833
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,356	2,349	2,343	2,336	2,329	2,323	2,316	2,310	2,303	2,296	2,290	2,283	27,833

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$344,257	344,257	344,257	344,257	344,257	344,257	344,257	344,257	344,257	344,257	344,257	344,257	344,257	
3	Less: Accumulated Depreciation	(615)	(1,846)	(3,077)	(4,308)	(5,538)	(6,769)	(8,000)	(9,230)	(10,461)	(11,692)	(12,923)	(14,153)	(15,384)	
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)	$343,641	342,411	341,180	339,949	338,718	337,488	336,257	335,026	333,796	332,565	331,334	330,103	328,873	
6	Average Net Investment		343,026	341,795	340,564	339,334	338,103	336,872	335,642	334,411	333,180	331,949	330,719	329,488	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		3,190	3,179	3,167	3,156	3,144	3,133	3,121	3,110	3,099	3,087	3,076	3,064	$37,526
	b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		583	581	579	577	575	573	571	568	566	564	562	560	6,860
8	Investment Expenses														
	a. Depreciation 4.29%		1,231	1,231	1,231	1,231	1,231	1,231	1,231	1,231	1,231	1,231	1,231	1,231	14,769
	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 0.008974		257	257	257	257	257	257	257	257	257	257	257	257	3,089
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		5,261	5,248	5,234	5,221	5,207	5,194	5,180	5,167	5,153	5,140	5,126	5,113	62,244
	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		5,261	5,248	5,234	5,221	5,207	5,194	5,180	5,167	5,153	5,140	5,126	5,113	62,244

For Project: UNDERGROUND STORAGE TANKS - CRYSTAL RIVER 4 & 5 (Project 10a)
(in Dollars)

Base

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation	(2,992)	(3,453)	(3,913)	(4,373)	(4,834)	(5,294)	(5,754)	(6,215)	(6,675)	(7,135)	(7,596)	(8,056)	(8,517)	
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)	$165,949	165,489	165,029	164,568	164,108	163,647	163,187	162,727	162,266	161,806	161,346	160,885	160,425	
6	Average Net Investment		165,719	165,259	164,798	164,338	163,878	163,417	162,957	162,497	162,036	161,576	161,115	160,655	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		1,541	1,537	1,533	1,528	1,524	1,520	1,516	1,511	1,507	1,503	1,498	1,494	$18,212
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		282	281	280	279	279	278	277	276	275	275	274	273	3,329
8	Investment Expenses														
	a. Depreciation 3.27%		460	460	460	460	460	460	460	460	460	460	460	460	5,524
	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 0.014268		201	201	201	201	201	201	201	201	201	201	201	201	2,410
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,484	2,479	2,474	2,469	2,464	2,459	2,454	2,449	2,444	2,439	2,433	2,428	29,475
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,484	2,479	2,474	2,469	2,464	2,459	2,454	2,449	2,444	2,439	2,433	2,428	29,475

For Project: UNDERGROUND STORAGE TANKS - BARTOW (Project 10b)
(in Dollars)

Intermediate

Line	Description	Beginning of Period Amount	Projected Jan-08	Projected Feb-08	Projected Mar-08	Projected Apr-08	Projected May-08	Projected Jun-08	Projected Jul-08	Projected Aug-08	Projected Sep-08	Projected Oct-08	Projected Nov-08	Projected Dec-08	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	$75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	75,868	
3	Less: Accumulated Depreciation	(2,319)	(2,520)	(2,722)	(2,924)	(3,126)	(3,327)	(3,529)	(3,731)	(3,932)	(4,134)	(4,336)	(4,537)	(4,739)	
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)	$73,549	73,348	73,146	72,944	72,742	72,541	72,339	72,137	71,936	71,734	71,532	71,331	71,129	
6	Average Net Investment		73,448	73,247	73,045	72,843	72,642	72,440	72,238	72,037	71,835	71,633	71,432	71,230	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		683	681	679	677	676	674	672	670	668	666	664	662	$8,073
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		125	125	124	124	123	123	123	122	122	122	121	121	1,476
8	Investment Expenses														
	a. Depreciation 3.19%		202	202	202	202	202	202	202	202	202	202	202	202	2,420
	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 0.009364		59	59	59	59	59	59	59	59	59	59	59	59	710
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,069	1,067	1,064	1,062	1,060	1,058	1,056	1,053	1,051	1,049	1,047	1,044	12,679
	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		1,069	1,067	1,064	1,062	1,060	1,058	1,056	1,053	1,051	1,049	1,047	1,044	12,679

Schedule 1A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Line		Period Amount ($)
1	End of Period Actual Total True-Up for the Period January 2006 - December 2006 (Schedule 2A, Line 5+6+10)	5,133,105
2	Estimated/Actual True-Up Amount approved for the period January 2006 - December 2006 (FPSC Order No. PSC-06-0972-FOF-EI)	2,874,720
3	Final True-Up Amount to be refunded/(recovered) in the projection period January 2008 - December 2008 (Lines 1 - 2)	2,258,385

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 40
COMPANY Gulf Power Company
WITNESS R.J. Martin (RJM-1)
DATE 11-06-07

Schedule 2A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

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)	3,020,378	2,809,043	2,691,281	3,001,576	3,633,381	4,218,255	4,330,525	4,458,823	3,710,112	3,118,132	2,870,819	3,074,716	40,937,041
2	True-Up Provision (Order No. PSC-05-1251-FOF-EI)	106,219	106,219	106,219	106,219	106,219	106,219	106,220	106,220	106,220	106,221	106,221	106,221	1,274,637
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	3,126,597	2,915,262	2,797,500	3,107,795	3,739,600	4,324,474	4,436,745	4,565,043	3,816,332	3,224,353	2,977,040	3,180,937	42,211,678
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5A, Line 9)	221,728	877,975	303,663	182,584	125,339	250,088	1,130,510	1,478,785	882,494	1,025,510	771,594	1,090,018	8,340,288
	b Capital Investment Projects (Schedule 7A, Line 9)	2,283,097	2,298,561	2,312,799	2,324,847	2,340,849	2,437,766	2,518,884	2,512,471	2,511,415	2,499,472	2,487,205	2,498,617	29,025,983
	c **Total Jurisdictional ECRC Costs**	2,504,825	3,176,536	2,616,462	2,507,431	2,466,188	2,687,854	3,649,394	3,991,256	3,393,909	3,524,982	3,258,799	3,588,635	37,366,271
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	621,772	(261,274)	181,038	600,364	1,273,412	1,636,620	787,351	573,787	422,423	(300,629)	(281,759)	(407,698)	4,845,407
6	Interest Provision (Schedule 3A, Line 10)	11,718	12,348	12,195	13,962	17,801	24,258	30,098	32,714	34,274	34,226	32,595	30,761	286,950
7	Beginning Balance True-Up & Interest Provision		2,833,649	2,478,504	2,565,518	3,073,625	4,258,619	5,813,278	6,524,507	7,024,788	7,375,265	7,002,641	6,647,256	
	a Actual Total for True-Up Period 2005	2,305,630												2,305,630
	b Final True-Up from January 2004 - December 2004 (Order No. PSC-05-1251-FOF-EI)	628,050	628,050	628,050	628,050	628,050	628,050	628,050	628,050	628,050	628,050	628,050	628,050	628,050
8	True-Up Collected/(Refunded) (see Line 2)	(106,219)	(106,219)	(106,219)	(106,219)	(106,219)	(106,219)	(106,220)	(106,220)	(106,220)	(106,221)	(106,221)	(106,221)	(1,274,637)
9	End of Period Total True-Up (Lines 5 + 6 + 7 + 7a + 7b + 8)	3,460,951	3,106,554	3,193,568	3,701,675	4,886,669	6,441,328	7,152,557	7,652,838	8,003,315	7,630,691	7,275,306	6,792,148	6,791,400
10	Adjustments to Period Total True-Up Including Interest*	748												748
11	**Current Period Total Net True-Up (Lines 9 + 10)**	3,461,699	3,106,554	3,193,568	3,701,675	4,886,669	6,441,328	7,152,557	7,652,838	8,003,315	7,630,691	7,275,306	6,792,148	6,792,148

**Prior period depreciation adjustment associated with the Plant Crist DEP Project.*

Schedule 3A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

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 7a +7b+ 10)	2,934,428	3,461,699	3,106,554	3,193,568	3,701,675	4,886,669	6,441,328	7,152,557	7,652,838	8,003,315	7,630,691	7,275,306	
2	Ending True-Up Amount Before Interest (Line 1 + Schedule 2A, Lines 5 + 8)	3,449,981	3,094,206	3,181,373	3,687,713	4,868,868	6,417,070	7,122,459	7,620,124	7,969,041	7,596,465	7,242,711	6,761,387	
3	Total of Beginning & Ending True-up (Lines 1 + 2)	6,384,409	6,555,905	6,287,927	6,881,281	8,570,543	11,303,739	13,563,787	14,772,681	15,621,879	15,599,780	14,873,402	14,036,693	
4	Average True-Up Amount (Line 3 x 1/2)	3,192,205	3,277,953	3,143,964	3,440,641	4,285,272	5,651,870	6,781,894	7,386,341	7,810,940	7,799,890	7,436,701	7,018,347	
5	Interest Rate (First Day of Reporting Business Month)	0.043000	0.045100	0.045300	0.047800	0.049600	0.050100	0.052900	0.053600	0.052700	0.052600	0.052700	0.052500	
6	Interest Rate (First Day of Subsequent Business Month)	0.045100	0.045300	0.047800	0.049600	0.050100	0.052900	0.053600	0.052700	0.052600	0.052700	0.052500	0.052700	
7	Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.088100	0.090400	0.093100	0.097400	0.099700	0.103000	0.106500	0.106300	0.105300	0.105300	0.105200	0.105200	
8	Average Interest Rate (Line 7 x 1/2)	0.044050	0.045200	0.046550	0.048700	0.049850	0.051500	0.053250	0.053150	0.052650	0.052650	0.052600	0.052600	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.003671	0.003767	0.003879	0.004058	0.004154	0.004292	0.004438	0.004429	0.004388	0.004388	0.004383	0.004383	
10	Interest Provision for the Month (Line 4 x Line 9)	11,718	12,348	12,195	13,962	17,801	24,258	30,098	32,714	34,274	34,226	32,595	30,761	286,950

Schedule 4A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

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	0	0	0	0.0	%
.2	Air Emission Fees	792,599	792,599	0	0.0	%
.3	Title V	54,846	72,460	(17,614)	(24.3)	%
.4	Asbestos Fees	0	(2,869)	2,869	100.0	%
.5	Emission Monitoring	523,060	545,520	(22,460)	(4.1)	%
.6	General Water Quality	386,587	517,166	(130,579)	(25.2)	%
.7	Groundwater Contamination Investigation	1,086,674	1,166,752	(80,078)	(6.9)	%
.8	State NPDES Administration	36,000	35,500	500	1.4	%
.9	Lead and Copper Rule	7,989	9,869	(1,880)	(19.0)	%
.10	Env Auditing/Assessment	12,209	12,972	(763)	(5.9)	%
.11	General Solid & Hazardous Waste	384,588	386,125	(1,537)	(0.4)	%
.12	Above Ground Storage Tanks	20,761	95,601	(74,840)	(78.3)	%
.13	Low NO_x	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	229,194	217,166	12,028	5.5	%
.17	Gulf Coast Ozone Study	0	0	0	0.0	%
.18	SPCC Substation Project	0	0	0	0.0	%
.19	FDEP NO_x Reduction Agreement	1,823,707	2,032,310	(208,603)	(10.3)	
.20	SO_2 Allowances	3,271,744	4,731,254	(1,459,510)	(30.8)	%
2	Total O & M Activities	8,629,958	10,612,425	(1,982,467)	(18.7)	%
3	Recoverable Costs Allocated to Energy	6,695,150	8,391,309	(1,696,159)	(20.2)	%
4	Recoverable Costs Allocated to Demand	1,934,808	2,221,116	(286,308)	(12.9)	%

Notes:
Column (1) is the End of Period Totals on Schedule 5A
Column (2) reflects the estimated/actual amount included in the estimated true-up approved by FPSC Order No. PSC-06-0972-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 2006 - December 2006

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	-	-	-	-	-	-	-	-	-	-	-	-	0		0
	.2 Air Emission Fees	-	668,225	-	-	-	-	-	-	-	124,374	-	-	792,599		792,599
	.3 Title V	8,385	3,938	3,776	11,922	3,249	2,759	(38)	643	4,602	4,651	5,415	5,544	54,846		54,846
	.4 Asbestos Fees	(4,369)	-	-	-	-	-	-	4,369	-	-	-	-	0	0	
	.5 Emission Monitoring	38,502	34,974	47,193	20,077	41,143	35,495	38,489	18,847	38,954	55,315	35,880	118,191	523,060		523,060
	.6 General Water Quality	23,101	19,165	28,183	19,846	18,805	50,408	53,615	3,027	61,955	23,526	65,144	19,812	386,587	386,587	
	.7 Groundwater Contamination Investigation	9,059	32,565	62,400	4,825	21,667	35,030	120,337	502,626	61,052	69,684	67,677	99,752	1,086,674	1,086,674	
	.8 State NPDES Administration	34,500	1,000	-	-	-	-	-	250	-	-	250	-	36,000	36,000	
	.9 Lead and Copper Rule	3,369	-	-	-	-	-	-	300	175	-	4,145	-	7,989	7,989	
	.10 Env Auditing/Assessment	2,585	440	7,123	1,565	(41)	-	-	-	-	-	94	443	12,209	12,209	
	.11 General Solid & Hazardous Waste	12,320	25,963	35,134	28,579	32,086	72,720	35,842	18,899	31,128	47,170	15,552	29,195	384,588	384,588	
	.12 Above Ground Storage Tanks	(60)	1,240	170	3,410	3,633	818	-	78	413	592	-	10,467	20,761	20,761	
	.13 Low NOx	-	-	-	-	-	-	-	-	-	-	-	-	0		0
	.14 Ash Pond Diversion Curtains	-	-	-	-	-	-	-	-	-	-	-	-	0		0
	.15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0		0
	.16 Sodium Injection	19,786	26,277	9,674	20,981	18,558	27,390	-	50,453	20,199	9,067	7,199	19,610	229,194		229,194
	.17 Gulf Coast Ozone Study	-	-	-	26,329	-	(26,329)	-	-	-	-	-	-	0		0
	.18 SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	-	-	0	0	
	.19 FDEP NO_X Reduction Agreement	95,886	109,476	133,857	64,330	92,986	162,429	227,901	202,012	140,448	218,143	99,933	276,306	1,823,707		1,823,707
	.20 SO_2 Allowances	(13,268)	(13,302)	(12,984)	(12,973)	(102,508)	(102,209)	692,294	727,667	552,473	508,319	497,587	550,648	3,271,744	0	3,271,744
2	Total of O & M Activities	229,796	909,961	314,526	188,891	129,578	258,511	1,168,440	1,529,171	911,399	1,060,841	798,876	1,129,968	8,629,958	1,934,808	6,695,150
3	Recoverable Costs Allocated to Energy	149,291	829,588	181,516	130,666	53,428	99,535	958,646	999,622	756,676	919,869	646,014	970,299	6,695,150		
4	Recoverable Costs Allocated to Demand	80,505	80,374	133,010	58,225	76,150	158,976	209,794	529,548	154,723	140,972	152,862	159,669	1,934,808		
5	Retail Energy Jurisdictional Factor	0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671			
6	Retail Demand Jurisdictional Factor	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872			
7	Jurisdictional Energy Recoverable Costs (A)	143,921	800,295	175,111	126,310	51,741	96,440	927,747	966,984	732,956	889,262	623,855	935,700	6,470,322		
8	Jurisdictional Demand Recoverable Costs (B)	77,807	77,680	128,552	56,274	73,598	153,648	202,763	511,801	149,538	136,248	147,739	154,318	1,869,966		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	221,728	877,975	303,663	182,584	125,339	250,088	1,130,510	1,478,785	882,494	1,025,510	771,594	1,090,018	8,340,288		

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 2006 - December 2006

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	33,057	33,057	0	0.0	%
.2	Crist 5, 6 & 7 Precipitator Projects	2,201,121	2,215,772	(14,651)	(0.7)	%
.3	Crist 7 Flue Gas Conditioning	169,667	169,881	(214)	(0.1)	%
.4	Low NOx Burners, Crist 6 & 7	2,175,993	2,175,845	148	0.0	%
.5	CEMS - Plants Crist, Scholz, Smith, Daniel	802,979	803,004	(25)	(0.0)	%
.6	Sub. Contam.Mobile Groundwater Treatment System	109,406	109,408	(2)	(0.0)	%
.7	Raw Water Well Flowmeters - Plants Crist & Smith	31,757	31,758	(1)	(0.0)	%
.8	Crist Cooling Tower Cell	90,698	90,887	(189)	(0.2)	%
.9	Crist 1-5 Dechlorination	32,530	32,530	0	0.0	%
.10	Crist Diesel Fuel Oil Remediation	8,053	8,053	0	0.0	%
.11	Crist Bulk Tanker Unload Secondary Containment Structure	10,814	10,814	0	0.0	%
.12	Crist IWW Sampling System	6,315	6,315	0	0.0	%
.13	Sodium Injection System	55,965	55,965	0	0.0	%
.14	Smith Stormwater Collection System	316,014	316,014	0	0.0	%
.15	Smith Waste Water Treatment Facility	39,973	39,974	(1)	(0.0)	%
.16	Daniel Ash Management Project	1,964,216	1,989,067	(24,851)	(1.2)	%
.17	Smith Water Conservation	19,354	19,354	0	0.0	%
.18	Underground Fuel Tank Replacement	0	0	0	0.0	%
.19	Crist DEP Project	19,560,794	19,145,821	414,973	2.2	%
.20	Crist Stormwater Collection System	30,460	39,478	(9,018)	(22.8)	%
.21	Crist Common FTIR Monitor	8,975	8,975	0	0.0	%
.22	Precipitator Upgrades for CAM Compliance	1,036,120	1,031,972	4,148	0.4	%
.23	Plant Groundwater Investigation	0	0	0	0.0	%
.24	Crist Water Conservation Project	1,467	3,300	(1,833)	(55.5)	%
.25	Crist Condenser Tubes	673,903	743,392	(69,489)	(9.3)	%
.26	SO_2 Allowances	652,057	614,344	37,713	6.1	%
2	Total Investment Projects - Recoverable Costs	30,031,688	29,694,980	336,708	1.1	%
3	Recoverable Costs Allocated to Energy	26,953,262	26,519,282	433,980	1.6	%
4	Recoverable Costs Allocated to Demand	3,078,426	3,175,698	(97,272)	(3.1)	%

Notes:
Column (1) is the End of Period Totals on Schedule 7A
Column (2) reflects the estimated/actual amount included in the estimated true-up approved by FPSC Order No. PSC-06-0972-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 2006 - December 2006

Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
	.1 Air Quality Assurance Testing	2,807	2,798	2,789	2,779	2,769	2,759	2,750	2,740	2,731	2,721	2,712	2,702	33,057	0	33,057
	.2 Crist 5, 6 & 7 Precipitator Projects	187,146	186,446	185,566	184,690	184,128	183,565	183,003	182,442	181,877	181,315	180,753	180,190	2,201,121	0	2,201,121
	.3 Crist 7 Flue Gas Conditioning	14,151	14,149	14,146	14,145	14,142	14,140	14,138	14,136	14,133	14,131	14,129	14,127	169,667	0	169,667
	.4 Low NOx Burners, Crist 6 & 7	182,888	182,536	182,264	181,993	181,721	181,451	181,178	180,908	180,635	180,363	180,130	179,926	2,175,993	0	2,175,993
	.5 CEMS - Plants Crist, Scholz, Smith, Daniel	67,573	67,566	67,452	67,307	67,299	67,103	66,778	66,650	66,514	66,377	66,244	66,115	802,979	0	802,979
	.6 Sub. Contam.Mobile Groundwater Treatment System	9,213	9,197	9,179	9,162	9,142	9,126	9,108	9,091	9,073	9,057	9,039	9,019	109,406	100,989	8,417
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	2,687	2,680	2,672	2,665	2,658	2,650	2,643	2,634	2,628	2,621	2,613	2,606	31,757	29,315	2,442
	.8 Crist Cooling Tower Cell	7,716	7,688	7,659	7,630	7,603	7,572	7,544	7,515	7,486	7,457	7,429	7,399	90,698	83,722	6,976
	.9 Crist 1-5 Dechlorination	2,761	2,751	2,743	2,734	2,724	2,715	2,706	2,697	2,688	2,679	2,670	2,662	32,530	30,028	2,502
	.10 Crist Diesel Fuel Oil Remediation	683	680	678	676	674	672	670	668	666	664	662	660	8,053	7,433	620
	.11 Crist Bulk Tanker Unload Secondary Containment Struc	918	914	912	909	905	903	900	896	894	891	887	885	10,814	9,982	832
	.12 Crist IWW Sampling System	536	534	533	531	529	527	525	524	522	520	518	516	6,315	5,829	486
	.13 Sodium Injection System	4,728	4,717	4,705	4,693	4,682	4,669	4,658	4,646	4,634	4,623	4,611	4,599	55,965	0	55,965
	.14 Smith Stormwater Collection System	26,804	26,718	26,633	26,547	26,463	26,378	26,292	26,207	26,121	26,036	25,950	25,865	316,014	291,705	24,309
	.15 Smith Waste Water Treatment Facility	3,361	3,356	3,350	3,345	3,339	3,334	3,329	3,322	3,317	3,312	3,307	3,301	39,973	36,898	3,075
	.16 Daniel Ash Management Project	152,758	152,349	152,624	155,180	159,740	162,307	164,897	168,860	171,559	172,743	173,625	177,574	1,964,216	1,813,122	151,094
	.17 Smith Water Conservation	1,623	1,633	1,629	1,625	1,620	1,616	1,612	1,608	1,604	1,598	1,595	1,591	19,354	17,865	1,489
	.18 Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.19 Crist DEP Project	1,618,739	1,617,503	1,617,148	1,616,129	1,624,644	1,639,924	1,643,648	1,640,303	1,639,670	1,638,121	1,633,707	1,631,258	19,560,794	0	19,560,794
	.20 Crist Stormwater Collection System	847	889	976	1,044	1,085	1,185	1,407	1,681	3,098	4,825	5,401	8,022	30,460	28,120	2,340
	.21 Crist Common FTIR Monitor	759	756	755	752	751	749	747	745	743	741	740	737	8,975	0	8,975
	.22 Precipitator Upgrades for CAM Compliance	78,797	78,665	82,347	85,612	85,788	85,975	86,313	86,755	87,147	87,437	87,653	103,631	1,036,120	0	1,036,120
	.23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 Crist Water Conservation Project	0	0	0	0	0	0	0	0	0	60	439	968	1,467	1,354	113
	.25 Crist Condenser Tubes	8,156	25,503	37,792	42,333	46,574	62,774	77,214	78,112	77,239	73,938	71,909	72,359	673,903	622,064	51,839
	.26 SO_2 Allowances	(7,894)	(7,734)	(7,575)	(7,417)	(11,275)	54,558	121,081	114,383	108,344	103,340	98,595	93,651	652,057	0	652,057
2	Total Investment Projects - Recoverable Costs	2,367,757	2,382,294	2,396,977	2,405,064	2,417,705	2,516,652	2,603,141	2,597,523	2,593,323	2,585,570	2,575,318	2,590,363	30,031,688	3,078,426	26,953,262
3	Recoverable Costs Allocated to Energy	2,166,470	2,165,469	2,168,626	2,170,250	2,174,887	2,256,567	2,327,280	2,317,078	2,310,034	2,302,739	2,292,815	2,301,046	26,953,262		
4	Recoverable Costs Allocated to Demand	201,288	216,825	228,351	234,814	242,818	260,085	275,861	280,444	283,289	282,830	282,503	289,318	3,078,426		
5	Retail Energy Jurisdictional Factor	0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671			
6	Retail Demand Jurisdictional Factor	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872			
7	Jurisdictional Energy Recoverable Costs (B)	2,088,555	2,089,002	2,092,101	2,097,902	2,106,169	2,186,397	2,252,268	2,241,425	2,237,620	2,226,120	2,214,169	2,218,995	26,050,723		
8	Jurisdictional Demand Recoverable Costs (C)	194,542	209,559	220,698	226,945	234,680	251,369	266,616	271,046	273,795	273,352	273,036	279,622	2,975,260		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	2,283,097	2,298,561	2,312,799	2,324,847	2,340,849	2,437,766	2,518,884	2,512,471	2,511,415	2,499,472	2,487,205	2,498,617	29,025,983		

Notes:

(A) Reference Pages 1-25 of Schedule 8A, Line 9 and Page 26 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 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1119, 1216, 1243, 1249
(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)														
	a Expenditures/Additions		(20,858)	81	64	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		(20,858)	81	64	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	198,000	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)	14,750,591	14,729,733	14,729,814	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	
3	Less: Accumulated Depreciation (C)	(1,262,042)	(1,322,320)	(1,382,565)	(1,244,496)	(1,304,114)	(1,363,733)	(1,423,351)	(1,482,970)	(1,542,590)	(1,602,208)	(1,661,826)	(1,721,444)	(1,781,062)	
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)	13,488,549	13,407,413	13,347,249	13,287,382	13,227,764	13,168,145	13,108,527	13,048,908	12,989,288	12,929,670	12,870,052	12,810,434	12,750,816	
6	Average Net Investment		13,447,981	13,377,331	13,317,316	13,257,573	13,197,955	13,138,336	13,078,718	13,019,098	12,959,479	12,899,861	12,840,243	12,780,625	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		98,802	98,283	97,842	97,403	96,965	96,527	96,089	95,651	95,213	94,775	94,337	93,899	1,155,786
	b Debt Component (Line 6 x Debt Component x 1/12)		28,066	27,918	27,793	27,669	27,544	27,420	27,295	27,171	27,046	26,922	26,798	26,673	328,315
8	Investment Expenses														
	a Depreciation (E)		46,682	46,649	46,335	46,022	46,023	46,022	46,023	46,024	46,022	46,022	46,022	46,022	553,868
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		13,596	13,596	13,596	13,596	13,596	13,596	13,596	13,596	13,596	13,596	13,596	13,596	163,152
	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)		187,146	186,446	185,566	184,690	184,128	183,565	183,003	182,442	181,877	181,315	180,753	180,190	2,201,121
	a Recoverable Costs Allocated to Energy		187,146	186,446	185,566	184,690	184,128	183,565	183,003	182,442	181,877	181,315	180,753	180,190	2,201,121
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		180,415	179,862	179,018	178,533	178,310	177,857	177,105	176,485	176,176	175,282	174,553	173,765	2,127,361
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)		180,415	179,862	179,018	178,533	178,310	177,857	177,105	176,485	176,176	175,282	174,553	173,765	2,127,361

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) 3.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

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)														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		135,214	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)	85,080	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	
3	Less: Accumulated Depreciation (C)	(29,586)	(30,599)	(31,612)	(32,625)	(33,637)	(34,650)	(35,663)	(36,676)	(37,689)	(38,702)	(39,715)	(40,727)	(41,740)	
4	CWIP - Non Interest Bearing	135,214	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	190,708	189,695	188,682	187,669	186,657	185,644	184,631	183,618	182,605	181,592	180,579	179,567	178,554	
6	Average Net Investment		190,202	189,189	188,176	187,163	186,150	185,137	184,124	183,112	182,099	181,086	180,073	179,060	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,397	1,390	1,383	1,375	1,368	1,360	1,353	1,345	1,338	1,330	1,323	1,316	16,278
	b Debt Component (Line 6 x Debt Component x 1/12)		397	395	393	391	388	386	384	382	380	378	376	374	4,624
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,012	12,155
	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)		2,807	2,798	2,789	2,779	2,769	2,759	2,750	2,740	2,731	2,721	2,712	2,702	33,057
	a Recoverable Costs Allocated to Energy		2,807	2,798	2,789	2,779	2,769	2,759	2,750	2,740	2,731	2,721	2,712	2,702	33,057
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		2,706	2,699	2,691	2,686	2,682	2,673	2,661	2,651	2,645	2,630	2,619	2,606	31,949
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)		2,706	2,699	2,691	2,686	2,682	2,673	2,661	2,651	2,645	2,630	2,619	2,606	31,949

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) PE 1006 is fully amortized. PE 1244 had a beginning balance of $85,080 and ending period balance of $220,294.
(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 Final True-Up Amount
January 2006 - December 2006

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)														
	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)	1,475,003	1,474,766	1,474,529	1,474,292	1,474,055	1,473,818	1,473,581	1,473,344	1,473,107	1,472,870	1,472,633	1,472,396	1,472,159	
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)	1,475,003	1,474,766	1,474,529	1,474,292	1,474,055	1,473,818	1,473,581	1,473,344	1,473,107	1,472,870	1,472,633	1,472,396	1,472,159	
6	Average Net Investment		1,474,885	1,474,648	1,474,411	1,474,174	1,473,937	1,473,700	1,473,463	1,473,226	1,472,989	1,472,752	1,472,515	1,472,278	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,836	10,834	10,832	10,831	10,829	10,827	10,826	10,824	10,822	10,820	10,819	10,817	129,917
	b Debt Component (Line 6 x Debt Component x 1/12)		3,078	3,078	3,077	3,077	3,076	3,076	3,075	3,075	3,074	3,074	3,073	3,073	36,906
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		237	237	237	237	237	237	237	237	237	237	237	237	2,844
	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)		14,151	14,149	14,146	14,145	14,142	14,140	14,138	14,136	14,133	14,131	14,129	14,127	169,667
	a Recoverable Costs Allocated to Energy		14,151	14,149	14,146	14,145	14,142	14,140	14,138	14,136	14,133	14,131	14,129	14,127	169,667
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		13,642	13,649	13,647	13,673	13,695	13,700	13,682	13,674	13,690	13,661	13,644	13,623	163,980
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)		13,642	13,649	13,647	13,673	13,695	13,700	13,682	13,674	13,690	13,661	13,644	13,623	163,980

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) 3.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242 & 1284
(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)														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	8,065	2,641	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	10,706	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		(17,169)	34	64	(36)	(44)	17	(17)	40	(4)	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	9,086,422	9,086,422	9,086,422	9,086,422	9,086,422	9,086,422	9,086,422	9,086,422	9,086,422	9,086,422	9,086,422	9,086,422	9,097,128	
3	Less: Accumulated Depreciation (C)	7,272,292	7,226,347	7,197,604	7,168,892	7,140,080	7,111,260	7,082,500	7,053,706	7,024,968	6,996,188	6,967,412	6,938,636	6,909,843	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	8,065	0	
5	Net Investment (Lines 2 + 3 + 4)	16,358,714	16,312,769	16,284,026	16,255,314	16,226,502	16,197,682	16,168,922	16,140,128	16,111,390	16,082,610	16,053,834	16,033,123	16,006,971	
6	Average Net Investment		16,335,742	16,298,398	16,269,670	16,240,908	16,212,092	16,183,302	16,154,525	16,125,759	16,097,000	16,068,222	16,043,479	16,020,047	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		120,019	119,744	119,533	119,322	119,110	118,899	118,687	118,476	118,265	118,053	117,871	117,699	1,425,678
	b Debt Component (Line 6 x Debt Component x 1/12)		34,093	34,015	33,955	33,895	33,835	33,775	33,714	33,654	33,594	33,534	33,483	33,434	404,981
8	Investment Expenses														
	a Depreciation (E)		28,776	28,777	28,776	28,776	28,776	28,777	28,777	28,778	28,776	28,776	28,776	28,793	345,317
	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)		182,888	182,536	182,264	181,993	181,721	181,451	181,178	180,908	180,635	180,363	180,130	179,926	2,175,993
	a Recoverable Costs Allocated to Energy		182,888	182,536	182,264	181,993	181,721	181,451	181,178	180,908	180,635	180,363	180,130	179,926	2,175,993
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		176,309	176,091	175,832	175,926	175,979	175,808	175,340	175,000	174,972	174,362	173,952	173,510	2,103,081
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)		176,309	176,091	175,832	175,926	175,979	175,808	175,340	175,000	174,972	174,362	173,952	173,510	2,103,081

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) 3.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist, Scholz, Smith, Daniel
P.E.s 1154, 1164, 1217, 1240, 1245, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1330, 1364, 1440, 1441, 1442, 1454, 1459, 1460, 1558, 1570, 1658
(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)														
	a Expenditures/Additions		14,298	5,116	(1,929)	(189)	19,786	877	0	0	0	0	0	0	
	b Clearings to Plant		14,298	5,116	(1,929)	(189)	19,786	877	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	125,113	0	0	3,452	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)	4,436,637	4,450,935	4,456,051	4,454,122	4,453,933	4,473,719	4,349,483	4,349,483	4,349,483	4,346,031	4,346,031	4,346,031	4,346,031	
3	Less: Accumulated Depreciation (C)	1,083,130	1,069,022	1,054,880	1,040,734	1,026,589	1,012,411	1,123,506	1,109,686	1,095,863	1,085,498	1,071,688	1,057,880	1,044,072	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	5,519,767	5,519,957	5,510,931	5,494,856	5,480,522	5,486,130	5,472,989	5,459,169	5,445,346	5,431,529	5,417,719	5,403,911	5,390,103	
6	Average Net Investment		5,519,862	5,515,444	5,502,894	5,487,689	5,483,326	5,479,560	5,466,079	5,452,258	5,438,438	5,424,624	5,410,815	5,397,007	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		40,554	40,522	40,430	40,318	40,286	40,258	40,159	40,058	39,956	39,855	39,753	39,652	481,801
	b Debt Component (Line 6 x Debt Component x 1/12)		11,520	11,511	11,485	11,453	11,444	11,436	11,408	11,379	11,350	11,321	11,292	11,264	136,863
8	Investment Expenses														
	a Depreciation (E)		13,976	14,010	14,014	14,013	14,046	13,886	13,688	13,690	13,685	13,678	13,676	13,676	166,038
	b Amortization (F)		132	132	132	132	132	132	132	132	132	132	132	132	1,585
	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)		67,573	67,566	67,452	67,307	67,299	67,103	66,778	66,650	66,514	66,377	66,244	66,115	802,979
	a Recoverable Costs Allocated to Energy		67,573	67,566	67,452	67,307	67,299	67,103	66,778	66,650	66,514	66,377	66,244	66,115	802,979
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		65,143	65,180	65,072	65,063	65,173	65,016	64,626	64,474	64,429	64,169	63,972	63,757	776,074
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)		65,143	65,180	65,072	65,063	65,173	65,016	64,626	64,474	64,429	64,169	63,972	63,757	776,074

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $2,357,715; Scholz $752,366; Smith $692,351; and Daniel $634,205. Ending Balances: Crist $2,232,602; Scholz $790,065; Smith $688,899; and Daniel $634,465
(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: 3.8%, Smith 3.9%, Scholz 4.2%, Daniel 3.1% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Substation Contamination Mobile Groundwater Treatment System
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)														
	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)	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	
3	Less: Accumulated Depreciation (C)	(135,224)	(137,060)	(138,897)	(140,733)	(142,567)	(144,403)	(146,240)	(148,076)	(149,912)	(151,748)	(153,584)	(155,420)	(157,256)	
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)	782,800	780,964	779,127	777,291	775,457	773,621	771,784	769,948	768,112	766,276	764,440	762,604	760,768	
6	Average Net Investment		781,883	780,046	778,210	776,375	774,540	772,703	770,867	769,031	767,195	765,359	763,523	761,687	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (		5,744	5,731	5,718	5,704	5,691	5,677	5,664	5,650	5,637	5,623	5,610	5,596	68,045
	b Debt Component (Line 6 x Debt Component x 1/12)		1,632	1,628	1,624	1,620	1,616	1,613	1,609	1,605	1,601	1,597	1,593	1,590	19,328
8	Investment Expenses														
	a Depreciation (E)		1,836	1,837	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	22,033
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		9,213	9,197	9,179	9,162	9,142	9,126	9,108	9,091	9,073	9,057	9,039	9,019	109,406
	a Recoverable Costs Allocated to Energy		710	707	706	705	703	703	700	699	698	696	696	694	8,417
	b Recoverable Costs Allocated to Demand		8,503	8,490	8,473	8,457	8,439	8,423	8,408	8,391	8,375	8,360	8,343	8,327	100,989
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		684	682	681	681	681	681	677	676	676	673	672	669	8,133
13	Retail Demand-Related Recoverable Costs (I)		8,218	8,205	8,189	8,174	8,156	8,141	8,126	8,110	8,094	8,080	8,063	8,048	97,604
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,902	8,887	8,870	8,855	8,837	8,822	8,803	8,786	8,770	8,753	8,735	8,717	105,737

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) 2.4% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

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)														
	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)	(40,122)	(40,899)	(41,676)	(42,453)	(43,230)	(44,008)	(44,785)	(45,562)	(46,338)	(47,114)	(47,891)	(48,668)	(49,444)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	202,821	202,044	201,267	200,490	199,713	198,935	198,158	197,381	196,605	195,829	195,052	194,275	193,499	
6	Average Net Investment		202,433	201,656	200,879	200,102	199,325	198,547	197,770	196,993	196,217	195,441	194,664	193,887	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,487	1,482	1,476	1,470	1,464	1,459	1,453	1,447	1,442	1,436	1,430	1,424	17,470
	b Debt Component (Line 6 x Debt Component x 1/12)		422	421	419	418	416	414	413	411	410	408	406	405	4,963
8	Investment Expenses														
	a Depreciation (E)		777	777	777	777	778	777	777	776	777	777	777	777	9,324
	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)		2,687	2,680	2,672	2,665	2,658	2,650	2,643	2,634	2,628	2,621	2,613	2,606	31,757
	a Recoverable Costs Allocated to Energy		206	206	206	205	205	204	203	203	202	201	201	200	2,442
	b Recoverable Costs Allocated to Demand		2,481	2,474	2,466	2,460	2,453	2,446	2,440	2,431	2,426	2,420	2,412	2,406	29,315
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		199	199	199	198	199	198	196	196	196	194	194	193	2,361
13	Retail Demand-Related Recoverable Costs (I)		2,398	2,391	2,383	2,378	2,371	2,364	2,358	2,350	2,345	2,339	2,331	2,325	28,333
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,597	2,590	2,582	2,576	2,570	2,562	2,554	2,546	2,541	2,533	2,525	2,518	30,694

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balance for Crist: $149,920; Beginning and Ending Balance for Smith $93,023
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist: 3.8% Smith 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments (A)														
	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)	(411,402)	(414,461)	(417,520)	(420,579)	(423,638)	(426,698)	(429,757)	(432,816)	(435,875)	(438,934)	(441,993)	(445,052)	(448,111)	
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)	495,257	492,198	489,139	486,080	483,021	479,961	476,902	473,843	470,784	467,725	464,666	461,607	458,548	
6	Average Net Investment		493,728	490,669	487,610	484,551	481,491	478,432	475,373	472,314	469,255	466,196	463,137	460,078	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,627	3,605	3,582	3,560	3,538	3,515	3,493	3,470	3,448	3,425	3,403	3,380	42,046
	b Debt Component (Line 6 x Debt Component x 1/12)		1,030	1,024	1,018	1,011	1,005	998	992	986	979	973	967	960	11,943
8	Investment Expenses														
	a Depreciation (E)		2,871	2,871	2,871	2,871	2,872	2,871	2,871	2,871	2,871	2,871	2,871	2,871	34,453
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		188	188	188	188	188	188	188	188	188	188	188	188	2,256
	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)		7,716	7,688	7,659	7,630	7,603	7,572	7,544	7,515	7,486	7,457	7,429	7,399	90,698
	a Recoverable Costs Allocated to Energy		594	591	589	587	585	582	580	578	576	574	571	569	6,976
	b Recoverable Costs Allocated to Demand		7,122	7,097	7,070	7,043	7,018	6,990	6,964	6,937	6,910	6,883	6,858	6,830	83,722
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		573	570	568	567	567	564	561	559	558	555	551	549	6,742
13	Retail Demand-Related Recoverable Costs (I)		6,883	6,859	6,833	6,807	6,783	6,756	6,731	6,705	6,678	6,652	6,628	6,601	80,916
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		7,456	7,429	7,401	7,374	7,350	7,320	7,292	7,264	7,236	7,207	7,179	7,150	87,658

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) 3.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

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)														
	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)	(114,711)	(115,678)	(116,645)	(117,612)	(118,579)	(119,546)	(120,513)	(121,480)	(122,447)	(123,414)	(124,381)	(125,348)	(126,316)	
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)	190,612	189,645	188,678	187,711	186,744	185,777	184,810	183,843	182,876	181,909	180,942	179,975	179,007	
6	Average Net Investment		190,129	189,162	188,195	187,228	186,261	185,294	184,327	183,360	182,393	181,426	180,459	179,491	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,397	1,390	1,383	1,376	1,368	1,361	1,354	1,347	1,340	1,333	1,326	1,319	16,294
	b Debt Component (Line 6 x Debt Component x 1/12)		397	395	393	391	389	387	385	383	381	379	377	375	4,632
8	Investment Expenses														
	a Depreciation (E)		967	966	967	967	967	967	967	967	967	967	967	968	11,604
	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)		2,761	2,751	2,743	2,734	2,724	2,715	2,706	2,697	2,688	2,679	2,670	2,662	32,530
	a Recoverable Costs Allocated to Energy		212	212	211	210	210	209	208	207	207	206	205	205	2,502
	b Recoverable Costs Allocated to Demand		2,549	2,539	2,532	2,524	2,514	2,506	2,498	2,490	2,481	2,473	2,465	2,457	30,028
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		204	205	204	203	203	203	201	200	201	199	198	198	2,419
13	Retail Demand-Related Recoverable Costs (I)		2,464	2,454	2,447	2,439	2,430	2,422	2,414	2,407	2,398	2,390	2,382	2,375	29,022
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,668	2,659	2,651	2,642	2,633	2,625	2,615	2,607	2,599	2,589	2,580	2,573	31,441

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) 3.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

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)														
	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)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(19,597)	(19,815)	(20,033)	(20,251)	(20,469)	(20,687)	(20,905)	(21,123)	(21,341)	(21,559)	(21,777)	(21,995)	(22,213)	
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)	49,326	49,108	48,890	48,672	48,454	48,236	48,018	47,800	47,582	47,364	47,146	46,928	46,710	
6	Average Net Investment		49,217	48,999	48,781	48,563	48,345	48,127	47,909	47,691	47,473	47,255	47,037	46,819	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		362	360	358	357	355	354	352	350	349	347	346	344	4,234
	b Debt Component (Line 6 x Debt Component x 1/12)		103	102	102	101	101	100	100	100	99	99	98	98	1,203
8	Investment Expenses														
	a Depreciation (E)		218	218	218	218	218	218	218	218	218	218	218	218	2,616
	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		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)		683	680	678	676	674	672	670	668	666	664	662	660	8,053
	a Recoverable Costs Allocated to Energy		53	52	52	52	52	52	52	51	51	51	51	51	620
	b Recoverable Costs Allocated to Demand		630	628	626	624	622	620	618	617	615	613	611	609	7,433
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		51	50	50	50	50	50	50	49	49	49	49	49	596
13	Retail Demand-Related Recoverable Costs (I)		609	607	605	603	601	599	597	596	594	592	591	589	7,183
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		660	657	655	653	651	649	647	645	643	641	640	638	7,779

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) 3.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unload Secondary Containment Structure
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)														
	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)	(38,070)	(38,391)	(38,712)	(39,033)	(39,354)	(39,675)	(39,996)	(40,317)	(40,638)	(40,959)	(41,280)	(41,601)	(41,922)	
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)	63,425	63,104	62,783	62,462	62,141	61,820	61,499	61,178	60,857	60,536	60,215	59,894	59,573	
6	Average Net Investment		63,265	62,944	62,623	62,302	61,981	61,660	61,339	61,018	60,697	60,376	60,055	59,734	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		465	462	460	458	455	453	451	448	446	444	441	439	5,422
	b Debt Component (Line 6 x Debt Component x 1/12)		132	131	131	130	129	129	128	127	127	126	125	125	1,540
8	Investment Expenses														
	a Depreciation (E)		321	321	321	321	321	321	321	321	321	321	321	321	3,852
	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)		918	914	912	909	905	903	900	896	894	891	887	885	10,814
	a Recoverable Costs Allocated to Energy		71	70	70	70	70	69	69	69	69	69	68	68	832
	b Recoverable Costs Allocated to Demand		847	844	842	839	835	834	831	827	825	822	819	817	9,982
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		68	68	68	68	68	67	67	67	67	67	66	66	807
13	Retail Demand-Related Recoverable Costs (I)		819	816	814	811	807	806	803	799	797	794	792	790	9,648
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		887	884	882	879	875	873	870	866	864	861	858	856	10,455

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) 3.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

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)														
	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)	(22,654)	(22,843)	(23,032)	(23,221)	(23,410)	(23,599)	(23,788)	(23,977)	(24,166)	(24,355)	(24,544)	(24,733)	(24,922)	
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)	36,889	36,700	36,511	36,322	36,133	35,944	35,755	35,566	35,377	35,188	34,999	34,810	34,621	
6	Average Net Investment		36,795	36,606	36,417	36,228	36,039	35,850	35,661	35,472	35,283	35,094	34,905	34,716	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		270	269	268	266	265	263	262	261	259	258	256	255	3,152
	b Debt Component (Line 6 x Debt Component x 1/12)		77	76	76	76	75	75	74	74	74	73	73	72	895
8	Investment Expenses														
	a Depreciation (E)		189	189	189	189	189	189	189	189	189	189	189	189	2,268
	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)		536	534	533	531	529	527	525	524	522	520	518	516	6,315
	a Recoverable Costs Allocated to Energy		41	41	41	41	41	41	40	40	40	40	40	40	486
	b Recoverable Costs Allocated to Demand		495	493	492	490	488	486	485	484	482	480	478	476	5,829
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		40	40	40	40	40	40	39	39	39	39	39	39	474
13	Retail Demand-Related Recoverable Costs (I)		478	476	476	474	472	470	469	468	466	464	462	460	5,635
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		518	516	516	514	512	510	508	507	505	503	501	499	6,109

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) 3.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214 and 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)														
	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)	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	
3	Less: Accumulated Depreciation (C)	(21,481)	(22,728)	(23,975)	(25,222)	(26,469)	(27,716)	(28,963)	(30,210)	(31,457)	(32,704)	(33,951)	(35,198)	(36,445)	
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)	369,638	368,391	367,144	365,897	364,650	363,403	362,156	360,909	359,662	358,415	357,168	355,921	354,674	
6	Average Net Investment		369,015	367,768	366,521	365,274	364,027	362,780	361,533	360,286	359,039	357,792	356,545	355,298	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,711	2,702	2,693	2,684	2,675	2,665	2,656	2,647	2,638	2,629	2,620	2,610	31,930
	b Debt Component (Line 6 x Debt Component x 1/12)		770	768	765	762	760	757	755	752	749	747	744	742	9,071
8	Investment Expenses														
	a Depreciation (E)		1,247	1,247	1,247	1,247	1,247	1,247	1,247	1,247	1,247	1,247	1,247	1,247	14,964
	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)		4,728	4,717	4,705	4,693	4,682	4,669	4,658	4,646	4,634	4,623	4,611	4,599	55,965
	a Recoverable Costs Allocated to Energy		4,728	4,717	4,705	4,693	4,682	4,669	4,658	4,646	4,634	4,623	4,611	4,599	55,965
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		4,558	4,550	4,539	4,537	4,534	4,524	4,508	4,494	4,489	4,469	4,453	4,435	54,090
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)		4,558	4,550	4,539	4,537	4,534	4,524	4,508	4,494	4,489	4,469	4,453	4,435	54,090

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and ending balances: Crist $284,622 and Smith $106,497
(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: 3.8% Smith 3.9% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

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)														
	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)	(895,435)	(904,478)	(913,521)	(922,564)	(931,607)	(940,650)	(949,693)	(958,736)	(967,779)	(976,822)	(985,865)	(994,908)	(1,003,951)	
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)	1,887,165	1,878,122	1,869,079	1,860,036	1,850,993	1,841,950	1,832,907	1,823,864	1,814,821	1,805,778	1,796,735	1,787,692	1,778,649	
6	Average Net Investment		1,882,644	1,873,601	1,864,558	1,855,515	1,846,472	1,837,429	1,828,386	1,819,343	1,810,300	1,801,257	1,792,214	1,783,171	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		13,832	13,765	13,699	13,632	13,566	13,500	13,433	13,367	13,300	13,234	13,167	13,101	161,596
	b Debt Component (Line 6 x Debt Component x 1/12)		3,929	3,910	3,891	3,872	3,854	3,835	3,816	3,797	3,778	3,759	3,740	3,721	45,902
8	Investment Expenses														
	a Depreciation (E)		9,043	9,043	9,043	9,043	9,043	9,043	9,043	9,043	9,043	9,043	9,043	9,043	108,516
	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)		26,804	26,718	26,633	26,547	26,463	26,378	26,292	26,207	26,121	26,036	25,950	25,865	316,014
	a Recoverable Costs Allocated to Energy		2,062	2,055	2,049	2,042	2,036	2,029	2,022	2,016	2,009	2,003	1,996	1,990	24,309
	b Recoverable Costs Allocated to Demand		24,742	24,663	24,584	24,505	24,427	24,349	24,270	24,191	24,112	24,033	23,954	23,875	291,705
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		1,988	1,982	1,977	1,974	1,972	1,966	1,957	1,950	1,946	1,936	1,928	1,919	23,495
13	Retail Demand-Related Recoverable Costs (I)		23,913	23,836	23,760	23,684	23,608	23,533	23,457	23,380	23,304	23,228	23,151	23,075	281,929
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		25,901	25,818	25,737	25,658	25,580	25,499	25,414	25,330	25,250	25,164	25,079	24,994	305,424

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 Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E. 1466 & 1643
(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)														
	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)	178,963	178,963	178,963	178,963	178,963	178,963	178,963	178,963	178,963	178,963	178,963	178,963	178,963	
3	Less: Accumulated Depreciation (C)	115,926	115,344	114,762	114,180	113,598	113,016	112,434	111,852	111,270	110,688	110,106	109,524	108,942	
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)	294,889	294,307	293,725	293,143	292,561	291,979	291,397	290,815	290,233	289,651	289,069	288,487	287,905	
6	Average Net Investment		294,598	294,016	293,434	292,852	292,270	291,688	291,106	290,524	289,942	289,360	288,778	288,196	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,164	2,160	2,156	2,152	2,147	2,143	2,139	2,134	2,130	2,126	2,122	2,117	25,690
	b Debt Component (Line 6 x Debt Component x 1/12)		615	614	612	611	610	609	608	606	605	604	603	601	7,298
8	Investment Expenses														
	a Depreciation (E)		582	582	582	582	582	582	582	582	582	582	582	583	6,985
	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)		3,361	3,356	3,350	3,345	3,339	3,334	3,329	3,322	3,317	3,312	3,307	3,301	39,973
	a Recoverable Costs Allocated to Energy		259	258	258	257	257	256	256	256	255	255	254	254	3,075
	b Recoverable Costs Allocated to Demand		3,103	3,098	3,092	3,088	3,082	3,078	3,073	3,066	3,062	3,057	3,053	3,046	36,898
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		250	249	249	248	249	248	248	248	247	247	245	245	2,973
13	Retail Demand-Related Recoverable Costs (I)		2,999	2,994	2,988	2,985	2,979	2,975	2,970	2,963	2,959	2,955	2,951	2,944	35,662
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,249	3,243	3,237	3,233	3,228	3,223	3,218	3,211	3,206	3,202	3,196	3,189	38,635

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 Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E. 1535, 1555 & 1819
(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)														
	a Expenditures/Additions		543	1,893	145,253	480,277	563,020	57,091	565,318	350,171	301,293	29,277	238,625	(122,446)	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	2,935,855	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	5,497	6,787	6,509	9,155	4,834	4,580	5,162	2,671	7,483	
	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	16,178,324	
3	Less: Accumulated Depreciation (C)	(4,794,905)	(4,839,422)	(4,883,939)	(4,928,456)	(4,967,476)	(5,005,207)	(5,043,215)	(5,078,577)	(5,118,260)	(5,158,197)	(5,197,551)	(5,239,397)	(5,280,222)	
4	CWIP - Non Interest Bearing	325,542	326,085	327,978	473,231	953,508	1,516,528	1,573,619	2,138,937	2,489,108	2,790,401	2,819,678	3,058,303	2	
5	Net Investment (Lines 2 + 3 + 4)	8,773,106	8,729,132	8,686,508	8,787,244	9,228,501	9,753,790	9,772,873	10,302,829	10,613,317	10,874,673	10,864,596	11,061,375	10,898,104	
6	Average Net Investment		8,751,119	8,707,820	8,736,876	9,007,873	9,491,146	9,763,332	10,037,851	10,458,073	10,743,995	10,869,635	10,962,986	10,979,740	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		64,294	63,976	64,190	66,181	69,731	71,731	73,748	76,835	78,936	79,859	80,545	80,668	870,694
	b Debt Component (Line 6 x Debt Component x 1/12)		18,264	18,173	18,234	18,799	19,808	20,376	20,949	21,826	22,423	22,685	22,880	22,915	247,332
8	Investment Expenses														
	a Depreciation (E)		34,205	34,205	34,205	34,205	34,206	34,205	34,205	34,205	34,205	34,204	34,205	37,996	414,251
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	123,744
	d Property Taxes		25,683	25,683	25,683	25,683	25,683	25,683	25,683	25,682	25,683	25,683	25,683	25,683	308,195
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		152,758	152,349	152,624	155,180	159,740	162,307	164,897	168,860	171,559	172,743	173,625	177,574	1,964,216
	a Recoverable Costs Allocated to Energy		11,751	11,719	11,740	11,937	12,288	12,485	12,684	12,989	13,197	13,288	13,356	13,660	151,094
	b Recoverable Costs Allocated to Demand		141,007	140,630	140,884	143,243	147,452	149,822	152,213	155,871	158,362	159,455	160,269	163,914	1,813,122
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		11,328	11,305	11,326	11,539	11,900	12,097	12,275	12,565	12,783	12,846	12,898	13,173	146,035
13	Retail Demand-Related Recoverable Costs (I)		136,281	135,917	136,163	138,443	142,510	144,801	147,112	150,647	153,055	154,111	154,898	158,421	1,752,359
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		147,609	147,222	147,489	149,982	154,410	156,898	159,387	163,212	165,838	166,957	167,796	171,594	1,898,394

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) 3.1% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 1620 & 1638
(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)														
	a Expenditures/Additions		2,166	(6)	19	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		2,166	(6)	19	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)	131,956	134,122	134,116	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	
3	Less: Accumulated Depreciation (C)	(6,635)	(7,068)	(7,504)	(7,940)	(8,376)	(8,810)	(9,246)	(9,682)	(10,118)	(10,552)	(10,986)	(11,421)	(11,855)	
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)	125,321	127,054	126,612	126,195	125,759	125,325	124,889	124,453	124,017	123,583	123,149	122,714	122,280	
6	Average Net Investment		126,188	126,833	126,404	125,977	125,542	125,107	124,671	124,235	123,800	123,366	122,932	122,497	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		927	932	929	926	922	919	916	913	910	906	903	900	11,003
	b Debt Component (Line 6 x Debt Component x 1/12)		263	265	264	263	262	261	260	259	258	257	257	256	3,125
8	Investment Expenses														
	a Depreciation (E)		433	436	436	436	436	436	436	436	436	435	435	435	5,226
	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)		1,623	1,633	1,629	1,625	1,620	1,616	1,612	1,608	1,604	1,598	1,595	1,591	19,354
	a Recoverable Costs Allocated to Energy		125	126	125	125	125	124	124	124	123	123	123	122	1,489
	b Recoverable Costs Allocated to Demand		1,498	1,507	1,504	1,500	1,495	1,492	1,488	1,484	1,481	1,475	1,472	1,469	17,865
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		121	122	121	121	121	120	120	120	119	119	119	118	1,441
13	Retail Demand-Related Recoverable Costs (I)		1,448	1,456	1,454	1,450	1,445	1,442	1,438	1,434	1,431	1,426	1,423	1,420	17,267
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,569	1,578	1,575	1,571	1,566	1,562	1,558	1,554	1,550	1,545	1,542	1,538	18,708

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) 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 Final True-Up Amount
January 2006 - December 2006

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)														
	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 (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component 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		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional 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
(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(s)
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Crist DEP Project
P.E. 1199, 1287, 1031
(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)														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	407,077	
	b Clearings to Plant		161,026	311,226	301,923	207,559	1,817,663	1,287,431	(11,084)	167,067	436,660	34,632	(32,192)	38,769	
	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)	129,117,654	129,278,680	129,589,906	129,891,829	130,099,388	131,917,051	133,204,482	133,193,398	133,360,465	133,797,125	133,831,757	133,799,565	133,838,334	
3	Less: Accumulated Depreciation (C)	(4,660,468)	(5,106,422)	(5,553,123)	(6,000,795)	(6,449,273)	(6,900,959)	(7,357,562)	(7,816,186)	(8,275,057)	(8,734,780)	(9,195,071)	(9,655,278)	(10,115,426)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	407,077	
5	Net Investment (Lines 2 + 3 + 4)	124,457,186	124,172,258	124,036,783	123,891,034	123,650,115	125,016,092	125,846,920	125,377,212	125,085,408	125,062,345	124,636,686	124,144,287	124,129,985	
6	Average Net Investment		124,314,722	124,104,521	123,963,909	123,770,575	124,333,104	125,431,506	125,612,066	125,231,310	125,073,877	124,849,516	124,390,487	124,137,136	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		913,340	911,796	910,763	909,342	913,475	921,545	922,872	920,074	918,918	917,269	913,897	912,036	10,985,327
	b Debt Component (Line 6 x Debt Component x 1/12)		259,445	259,006	258,713	258,309	259,483	261,776	262,152	261,358	261,029	260,561	259,603	259,074	3,120,509
8	Investment Expenses														
	a Depreciation (E)		409,056	409,803	410,774	411,580	414,788	419,705	421,726	421,973	422,825	423,393	423,309	423,250	5,012,182
	b Amortization (F)		433	433	433	433	433	433	433	433	433	433	433	433	5,196
	c Dismantlement		36,465	36,465	36,465	36,465	36,465	36,465	36,465	36,465	36,465	36,465	36,465	36,465	437,580
	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)		1,618,739	1,617,503	1,617,148	1,616,129	1,624,644	1,639,924	1,643,648	1,640,303	1,639,670	1,638,121	1,633,707	1,631,258	19,560,794
	a Recoverable Costs Allocated to Energy		1,618,739	1,617,503	1,617,148	1,616,129	1,624,644	1,639,924	1,643,648	1,640,303	1,639,670	1,638,121	1,633,707	1,631,258	19,560,794
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		1,560,523	1,560,386	1,560,083	1,562,254	1,573,311	1,588,929	1,590,671	1,586,747	1,588,271	1,583,616	1,577,669	1,573,090	18,905,550
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)		1,560,523	1,560,386	1,560,083	1,562,254	1,573,311	1,588,929	1,590,671	1,586,747	1,588,271	1,583,616	1,577,669	1,573,090	18,905,550

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.8% annually
(F) 7 year amortization
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Stormwater Collection System
P.E. 1272
(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)														
	a Expenditures/Additions		1,993	6,908	11,587	2,825	5,884	15,249	31,878	26,190	274,107	92,082	29,882	247,142	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	834,527	
	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	834,527	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	(1,321)	
4	CWIP - Non Interest Bearing	88,798	90,791	97,699	109,286	112,111	117,995	133,244	165,122	191,312	465,419	557,501	587,383	(2)	
5	Net Investment (Lines 2 + 3 + 4)	88,798	90,791	97,699	109,286	112,111	117,995	133,244	165,122	191,312	465,419	557,501	587,383	833,204	
6	Average Net Investment		89,795	94,245	103,493	110,699	115,053	125,620	149,183	178,217	328,366	511,460	572,442	710,294	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		660	692	760	813	845	923	1,096	1,309	2,413	3,758	4,206	5,219	22,694
	b Debt Component (Line 6 x Debt Component x 1/12)		187	197	216	231	240	262	311	372	685	1,067	1,195	1,482	6,445
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	1,321	1,321
	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)		847	889	976	1,044	1,085	1,185	1,407	1,681	3,098	4,825	5,401	8,022	30,460
	a Recoverable Costs Allocated to Energy		65	68	75	80	83	91	108	129	238	371	415	617	2,340
	b Recoverable Costs Allocated to Demand		782	821	901	964	1,002	1,094	1,299	1,552	2,860	4,454	4,986	7,405	28,120
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		63	66	72	77	80	88	105	125	231	359	401	595	2,262
13	Retail Demand-Related Recoverable Costs (I)		756	793	871	932	968	1,057	1,255	1,500	2,764	4,305	4,819	7,157	27,177
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		819	859	943	1,009	1,048	1,145	1,360	1,625	2,995	4,664	5,220	7,752	29,439

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) 3.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E.s 1297
(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)														
	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)	62,871	62,871	62,871	62,871	62,871	62,871	62,871	62,871	62,871	62,871	62,871	62,871	62,871	
3	Less: Accumulated Depreciation (C)	(3,494)	(3,693)	(3,892)	(4,091)	(4,290)	(4,489)	(4,688)	(4,887)	(5,086)	(5,285)	(5,484)	(5,683)	(5,882)	
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)	59,377	59,178	58,979	58,780	58,581	58,382	58,183	57,984	57,785	57,586	57,387	57,188	56,989	
6	Average Net Investment		59,278	59,079	58,880	58,681	58,482	58,283	58,084	57,885	57,686	57,487	57,288	57,089	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		436	434	433	431	430	428	427	425	424	422	421	419	5,130
	b Debt Component (Line 6 x Debt Component x 1/12)		124	123	123	122	122	122	121	121	120	120	120	119	1,457
8	Investment Expenses														
	a Depreciation (E)		199	199	199	199	199	199	199	199	199	199	199	199	2,388
	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)		759	756	755	752	751	749	747	745	743	741	740	737	8,975
	a Recoverable Costs Allocated to Energy		759	756	755	752	751	749	747	745	743	741	740	737	8,975
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		732	729	728	727	727	726	723	721	720	716	715	711	8,675
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)		732	729	728	727	727	726	723	721	720	716	715	711	8,675

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) 3.8% annually
(F) 7 year amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E.s 1461 & 1462
(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)														
	a Expenditures/Additions		(87,000)	100,931	537,215	43,651	37,928	45,906	69,960	68,389	58,731	46,762	43,537	3,388,053	
	b Clearings to Plant		(87,000)	84,500	450,000	0	0	(100)	(114)	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)	6,360,832	6,273,832	6,358,332	6,808,332	6,808,332	6,808,332	6,808,232	6,808,118	6,808,118	6,808,118	6,808,118	6,808,118	6,808,118	
3	Less: Accumulated Depreciation (C)	(130,876)	(151,407)	(171,934)	(193,330)	(215,457)	(237,584)	(259,711)	(281,838)	(303,964)	(326,090)	(348,217)	(370,343)	(392,469)	
4	CWIP - Non Interest Bearing	0	0	16,431	103,646	147,297	185,225	231,231	301,305	369,694	428,425	475,187	518,724	3,906,777	
5	Net Investment (Lines 2 + 3 + 4)	6,229,956	6,122,425	6,202,829	6,718,648	6,740,172	6,755,973	6,779,752	6,827,585	6,873,848	6,910,453	6,935,088	6,956,499	10,322,426	
6	Average Net Investment		6,176,191	6,162,627	6,460,739	6,729,410	6,748,073	6,767,863	6,803,669	6,850,717	6,892,151	6,922,771	6,945,794	8,639,463	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		45,376	45,277	47,467	49,441	49,578	49,723	49,987	50,332	50,637	50,862	51,031	63,474	603,185
	b Debt Component (Line 6 x Debt Component x 1/12)		12,890	12,861	13,484	14,044	14,083	14,125	14,199	14,297	14,384	14,448	14,496	18,031	171,342
8	Investment Expenses														
	a Depreciation (E)		20,531	20,527	21,396	22,127	22,127	22,127	22,127	22,126	22,126	22,127	22,126	22,126	261,593
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		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)		78,797	78,665	82,347	85,612	85,788	85,975	86,313	86,755	87,147	87,437	87,653	103,631	1,036,120
	a Recoverable Costs Allocated to Energy		78,797	78,665	82,347	85,612	85,788	85,975	86,313	86,755	87,147	87,437	87,653	103,631	1,036,120
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		75,963	75,887	79,441	82,758	83,077	83,302	83,531	83,922	84,415	84,528	84,646	99,936	1,001,406
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)		75,963	75,887	79,441	82,758	83,077	83,302	83,531	83,922	84,415	84,528	84,646	99,936	1,001,406

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 Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E. 1218, 1361
(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)														
	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 (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component 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		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional 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
(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(s)
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Water Conservation Project
P.E. 1227
(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)														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	12,885	67,376	13,474	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	93,735	
	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	93,735	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	(148)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	12,885	80,261	0	
5	Net Investment (Lines 2 + 3 + 4)	0	0	0	0	0	0	0	0	0	0	12,885	80,261	93,587	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	6,443	46,573	86,924	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	47	342	639	1,028
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	13	97	181	291
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	148	148
	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	60	439	968	1,467
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	5	34	74	113
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	55	405	894	1,354
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	5	33	71	109
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	53	391	864	1,308
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	58	424	935	1,417

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) 3.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Condenser Tubes
P.E. 1204
(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)														
	a Expenditures/Additions		1,729,113	1,936,494	651,474	299,113	632,097	804,028	179,432	(7,615)	(101,437)	(393,806)	99,656	(842)	
	b Clearings to Plant		0	0	0	0	0	6,052,319	179,432	(7,615)	(101,437)	(393,806)	99,656	(842)	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	11,974	5,269	6,708	7,811	(31,762)	0	0	0	0	0	0	
	e Salvage		0	0	0	0	46,497	(46,497)	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	6,052,319	6,231,751	6,224,136	6,122,699	5,728,893	5,828,549	5,827,707	
3	Less: Accumulated Depreciation (C)	0	0	11,974	17,243	23,951	(14,735)	(9,584)	(29,036)	(48,760)	(68,311)	(87,078)	(105,379)	(123,837)	
4	CWIP - Non Interest Bearing	0	1,729,113	3,665,607	4,317,081	4,616,194	5,248,291	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	0	1,729,113	3,677,581	4,334,324	4,640,145	5,233,556	6,042,735	6,202,715	6,175,376	6,054,388	5,641,815	5,723,170	5,703,870	
6	Average Net Investment		864,557	2,703,347	4,005,953	4,487,235	4,936,851	5,638,146	6,122,725	6,189,046	6,114,882	5,848,102	5,682,493	5,713,520	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,352	19,861	29,432	32,968	36,271	41,423	44,984	45,471	44,926	42,966	41,749	41,977	428,380
	b Debt Component (Line 6 x Debt Component x 1/12)		1,804	5,642	8,360	9,365	10,303	11,767	12,778	12,917	12,762	12,205	11,859	11,924	121,686
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	9,584	19,452	19,724	19,551	18,767	18,301	18,458	123,837
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		8,156	25,503	37,792	42,333	46,574	62,774	77,214	78,112	77,239	73,938	71,909	72,359	673,903
	a Recoverable Costs Allocated to Energy		627	1,962	2,907	3,256	3,583	4,829	5,940	6,009	5,941	5,688	5,531	5,566	51,839
	b Recoverable Costs Allocated to Demand		7,529	23,541	34,885	39,077	42,991	57,945	71,274	72,103	71,298	68,250	66,378	66,793	622,064
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		604	1,893	2,804	3,147	3,470	4,679	5,749	5,813	5,755	5,499	5,341	5,368	50,122
13	Retail Demand-Related Recoverable Costs (I)		7,277	22,752	33,716	37,767	41,550	56,003	68,885	69,687	68,909	65,963	64,153	64,555	601,217
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		7,881	24,645	36,520	40,914	45,020	60,682	74,634	75,500	74,664	71,462	69,494	69,923	651,339

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) 3.8% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2006 - December 2006

Return on Working Capital, SO_2 Allowance Expenses
For Project: SO_2 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	7,500	0	7,500	0	14,700,000	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	940,970	7,251	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	6,186	5,917	13,182	12,629	19,565	18,809	14,717,754	13,922,196	13,091,265	12,435,528	11,823,945	11,223,094	10,583,118	
	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	(849,601)	(836,064)	(822,527)	(808,990)	(795,453)	(1,633,159)	(1,537,146)	(1,433,882)	(1,330,618)	(1,227,354)	(1,124,090)	(1,020,826)	(931,498)	
3	Total Working Capital Balance	(843,415)	(830,147)	(809,345)	(796,361)	(775,888)	(1,614,350)	13,180,608	12,488,314	11,760,647	11,208,174	10,699,855	10,202,268	9,651,620	
4	Average Net Working Capital Balance		(836,781)	(819,746)	(802,853)	(786,125)	(1,195,119)	5,783,129	12,834,461	12,124,481	11,484,411	10,954,015	10,451,062	9,926,944	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		(6,148)	(6,023)	(5,899)	(5,776)	(8,781)	42,489	94,295	89,079	84,376	80,479	76,784	72,933	507,808
	b Debt Component (Line 4 x Debt Component x 1/12)		(1,746)	(1,711)	(1,676)	(1,641)	(2,494)	12,069	26,786	25,304	23,968	22,861	21,811	20,718	144,249
6	Total Return Component (D)		(7,894)	(7,734)	(7,575)	(7,417)	(11,275)	54,558	121,081	114,383	108,344	103,340	98,595	93,651	652,057
7	Expenses														
	a Gains		(13,537)	(13,537)	(13,537)	(13,537)	(103,264)	(103,264)	(103,264)	(103,264)	(103,264)	(103,264)	(103,264)	(89,328)	(866,324)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO_2 Allowance Expense		269	235	553	564	756	1,055	795,558	830,931	655,737	611,583	600,851	639,976	4,138,068
8	Net Expenses (E)		(13,268)	(13,302)	(12,984)	(12,973)	(102,508)	(102,209)	692,294	727,667	552,473	508,319	497,587	550,648	3,271,744
9	Total System Recoverable Expenses (Lines 6 + 8)		(21,162)	(21,036)	(20,559)	(20,390)	(113,783)	(47,651)	813,375	842,050	660,817	611,659	596,182	644,299	3,923,801
	a Recoverable Costs Allocated to Energy		(21,162)	(21,036)	(20,559)	(20,390)	(113,783)	(47,651)	813,375	842,050	660,817	611,659	596,182	644,299	3,923,801
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9633616	0.9640134	0.9640379	0.9659877	0.9677263	0.9682262	0.9670916	0.9666733	0.9679750	0.9660509	0.9650235	0.9636671	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (B)		(20,401)	(20,293)	(19,834)	(19,710)	(110,188)	(46,169)	787,159	814,557	640,102	591,307	575,732	621,324	3,793,586
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)		(20,401)	(20,293)	(19,834)	(19,710)	(110,188)	(46,169)	787,159	814,557	640,102	591,307	575,732	621,324	3,793,586

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 12%.
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6A and 7A
(E) Line 8 is reported on Schedule 4A and 5A

Schedule 1E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2007 - December 2007

Line		Period Amount ($)
1	Over/(Under) Recovery for the current period (Schedule 2E, Line 5)	(2,308,659)
2	Interest Provision (Schedule 2E, Line 6)	190,733
3	Current Period True-Up Amount to be refunded/(recovered) in the projection period January 2008 - December 2008 (Lines 1 + 2)	(2,117,926)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 41
COMPANY Gulf Power Company
WITNESS K. D. Martin (Exh-2)
DATE 11-01-07

Schedule 2E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2007 - December 2007

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)	3,365,831	3,065,975	2,996,329	2,988,676	3,728,111	4,237,777	4,524,280	4,598,087	3,859,523	3,306,842	3,031,754	3,400,524	43,103,709
2	True-Up Provision (Order No. PSC-06-0972-FOF-EI)	377,814	377,814	377,814	377,814	377,814	377,814	377,814	377,814	377,814	377,814	377,814	377,809	4,533,763
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	3,743,645	3,443,789	3,374,143	3,366,490	4,105,925	4,615,591	4,902,094	4,975,901	4,237,337	3,684,656	3,409,568	3,778,333	47,637,472
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5E, Line 9)	909,280	1,898,401	1,389,700	999,142	1,306,224	1,589,433	1,817,420	1,649,848	1,560,234	1,437,339	1,271,540	1,413,273	17,241,834
	b Capital Investment Projects (Schedule 7E, Line 9)	2,487,325	2,543,601	2,542,041	2,554,732	2,574,053	2,730,204	2,877,317	2,870,491	2,866,267	2,865,855	2,884,019	2,908,392	32,704,297
	c **Total Jurisdictional ECRC Costs**	3,396,605	4,442,002	3,931,741	3,553,874	3,880,277	4,319,637	4,694,737	4,520,339	4,426,501	4,303,194	4,155,559	4,321,665	49,946,131
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	347,040	(998,213)	(557,598)	(187,384)	225,648	295,954	207,357	455,562	(189,164)	(618,538)	(745,991)	(543,332)	(2,308,659)
6	Interest Provision (Schedule 3E, Line 10)	29,736	26,327	20,955	17,758	16,264	15,855	15,398	15,262	14,253	10,876	6,260	1,789	190,733
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2006	5,133,105	5,132,067	3,589,625	2,675,168	2,127,728	1,991,826	1,925,821	1,770,762	1,863,772	1,311,047	325,571	(791,974)	5,133,105
	b Final True-Up from January 2005 - December 2005 (Order No. PSC-06-0972-FOF-EI)	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043	1,659,043
8	True-Up Collected/(Refunded) (see Line 2)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,814)	(377,809)	(4,533,763)
9	Adjustments		(192,742)											
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8)	6,791,110	5,248,668	4,334,211	3,786,771	3,650,869	3,584,864	3,429,805	3,522,815	2,970,090	1,984,614	867,069	(52,283)	140,459

Schedule 3E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2007 - December 2007

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 7a + 7b)	6,792,148	6,791,110	5,248,668	4,334,211	3,786,771	3,650,869	3,584,864	3,429,805	3,522,815	2,970,090	1,984,614	867,069	
2 Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8)	6,761,374	5,222,341	4,313,256	3,769,013	3,634,605	3,569,009	3,414,407	3,507,553	2,955,837	1,973,738	860,809	(54,072)	
3 Total of Beginning & Ending True-up (Lines 1 + 2)	13,553,522	12,013,451	9,561,924	8,103,224	7,421,376	7,219,878	6,999,271	6,937,358	6,478,652	4,943,828	2,845,423	812,997	
4 Average True-Up Amount (Line 3 x 1/2)	6,776,761	6,006,726	4,780,962	4,051,612	3,710,688	3,609,939	3,499,636	3,468,679	3,239,326	2,471,914	1,422,712	406,499	
5 Interest Rate (First Day of Reporting Business Month)	0.052700	0.052600	0.052600	0.052600	0.052600	0.052600	0.052800	0.052800	0.052800	0.052800	0.052800	0.052800	
6 Interest Rate (First Day of Subsequent Business Month)	0.052600	0.052600	0.052600	0.052600	0.052600	0.052800	0.052800	0.052800	0.052800	0.052800	0.052800	0.052800	
7 Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.105300	0.105200	0.105200	0.105200	0.105200	0.105400	0.105600	0.105600	0.105600	0.105600	0.105600	0.105600	
8 Average Interest Rate (Line 7 x 1/2)	0.052650	0.052600	0.052600	0.052600	0.052600	0.052700	0.052800	0.052800	0.052800	0.052800	0.052800	0.052800	
9 Monthly Average Interest Rate (Line 8 x 1/12)	0.004388	0.004383	0.004383	0.004383	0.004383	0.004392	0.004400	0.004400	0.004400	0.004400	0.004400	0.004400	
10 Interest Provision for the Month (Line 4 x Line 9)	29,736	26,327	20,955	17,758	16,264	15,855	15,398	15,262	14,253	10,876	6,260	1,789	190,733

Schedule 4E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2007 - December 2007

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	0	0	0	0.0	%
.2	Air Emission Fees	803,824	779,874	23,950	3.1	%
.3	Title V	80,320	87,456	(7,136)	(8.2)	%
.4	Asbestos Fees	2,500	2,250	250	11.1	%
.5	Emission Monitoring	480,665	580,357	(99,692)	(17.2)	%
.6	General Water Quality	344,221	485,287	(141,066)	(29.1)	%
.7	Groundwater Contamination Investigation	1,352,251	1,352,251	0	0.0	%
.8	State NPDES Administration	34,750	42,000	(7,250)	(17.3)	%
.9	Lead and Copper Rule	19,553	10,000	9,553	95.5	%
.10	Env Auditing/Assessment	10,462	4,300	6,162	143.3	%
.11	General Solid & Hazardous Waste	552,933	485,428	67,505	13.9	%
.12	Above Ground Storage Tanks	101,050	101,050	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	211,531	275,000	(63,469)	(23.1)	%
.17	Gulf Coast Ozone Study	0	0	0	0.0	%
.18	SPCC Substation Project	0	0	0	0.0	%
.19	FDEP NOX Reduction Agreement	2,970,940	3,071,207	(100,267)	(3.3)	%
.20	SO2 Allowances	10,884,512	5,970,503	4,914,009	82.3	%
2	Total O & M Activities	17,849,512	13,246,963	4,602,549	34.7	%
3	Recoverable Costs Allocated to Energy	15,431,792	10,764,397	4,667,395	43.4	%
4	Recoverable Costs Allocated to Demand	2,417,720	2,482,566	(64,846)	(2.6)	%

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-06-0972-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Schedule 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2007 - December 2007

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	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.2 Air Emission Fees	-	679,450	-	-	-	-	-	-	124,374	-	-	-	803,824	0	803,824
	.3 Title V	5,189	6,687	5,028	4,791	6,857	5,049	4,732	3,286	5,615	10,830	11,051	11,205	80,320	0	80,320
	.4 Asbestos Fees	-	1,500	1,000	-	-	-	-	-	-	-	-	-	2,500	2,500	0
	.5 Emission Monitoring	27,555	33,940	34,654	27,982	11,475	60,996	36,786	63,160	44,421	56,528	41,528	41,640	480,665	0	480,665
	.6 General Water Quality	(154)	5,489	34,117	26,588	(8,045)	43,513	20,956	46,206	35,683	30,706	73,956	35,206	344,221	344,221	0
	.7 Groundwater Contamination Investigation	8,100	55,782	60,973	36,155	53,269	270,253	404,600	204,161	51,719	61,097	53,675	92,467	1,352,251	1,352,251	0
	.8 State NPDES Administration	34,500	-	-	-	-	250	-	-	-	-	-	-	34,750	34,750	0
	.9 Lead and Copper Rule	3,386	-	-	3,558	-	4,209	-	4,200	-	-	4,200	-	19,553	19,553	0
	.10 Env Auditing/Assessment	-	-	14	-	8,761	1,087	-	250	250	-	-	100	10,462	10,462	0
	.11 General Solid & Hazardous Waste	172,717	25,677	44,095	49,856	86,091	66,031	16,189	20,025	16,189	18,689	18,689	18,685	552,933	552,933	0
	.12 Above Ground Storage Tanks	-	-	16,623	175	29,434	(8,816)	-	-	3,800	31,000	20,000	8,834	101,050	101,050	0
	.13 Low Nox	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.14 Ash Pond Diversion Curtains	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.16 Sodium Injection	14,066	16,005	14,426	14,026	21,746	9,262	14,000	17,500	23,500	23,500	23,500	20,000	211,531	0	211,531
	.17 Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.18 SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.19 FDEP NOX Reduction Agreement	230,029	225,634	217,368	156,712	254,786	228,898	274,481	229,152	298,349	320,339	249,601	285,591	2,970,940	0	2,970,940
	.20 SO2 Allowances	446,393	918,490	1,009,941	713,763	885,676	962,600	1,107,073	1,117,375	1,010,918	937,016	823,141	952,126	10,884,512	0	10,884,512
2	Total of O & M Activities	941,781	1,968,654	1,438,239	1,033,606	1,350,050	1,643,332	1,878,817	1,705,315	1,614,818	1,489,705	1,319,341	1,465,854	17,849,512	2,417,720	15,431,792
3	Recoverable Costs Allocated to Energy	723,232	1,880,206	1,281,417	917,274	1,180,540	1,266,805	1,437,072	1,430,473	1,507,177	1,348,213	1,148,821	1,310,562	15,431,792		
4	Recoverable Costs Allocated to Demand	218,549	88,448	156,822	116,332	169,510	376,527	441,745	274,842	107,641	141,492	170,520	155,292	2,417,720		
5	Retail Energy Jurisdictional Factor	0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757			
6	Retail Demand Jurisdictional Factor	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872			
7	Jurisdictional Energy Recoverable Costs (A)	698,055	1,812,917	1,238,134	886,709	1,142,395	1,225,524	1,390,479	1,384,217	1,456,200	1,300,589	1,106,735	1,263,185	14,905,139		
8	Jurisdictional Demand Recoverable Costs (B)	211,225	85,484	151,566	112,433	163,829	363,909	426,941	265,631	104,034	136,750	164,805	150,088	2,336,695		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	909,280	1,898,401	1,389,700	999,142	1,306,224	1,589,433	1,817,420	1,649,848	1,560,234	1,437,339	1,271,540	1,413,273	17,241,834		

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 2007 - December 2007

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	49,907	49,908	(1)	(0.0)	%
.2	Crist 5, 6 & 7 Precipitator Projects	2,011,027	2,116,656	(105,629)	(5.0)	%
.3	Crist 7 Flue Gas Conditioning	168,969	169,317	(348)	(0.2)	%
.4	Low NOx Burners, Crist 6 & 7	2,085,306	2,136,673	(51,367)	(2.4)	%
.5	CEMS - Plants Crist, Scholz, Smith, & Daniel	770,919	788,061	(17,142)	(2.2)	%
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	106,908	106,910	(2)	(0.0)	%
.7	Raw Water Well Flowmeters - Plants Crist & Smith	28,631	30,702	(2,071)	(6.7)	%
.8	Crist Cooling Tower Cell	73,956	65,751	8,205	12.5	%
.9	Crist 1-5 Dechlorination	29,478	31,212	(1,734)	(5.6)	%
.10	Crist Diesel Fuel Oil Remediation	7,371	7,756	(385)	(5.0)	%
.11	Crist Bulk Tanker Unload Sec Contain Struc	9,815	10,379	(564)	(5.4)	%
.12	Crist IWW Sampling System	5,718	6,060	(342)	(5.6)	%
.13	Sodium Injection System	51,259	54,268	(3,009)	(5.5)	%
.14	Smith Stormwater Collection System	266,972	303,732	(36,760)	(12.1)	%
.15	Smith Waste Water Treatment Facility	36,814	39,182	(2,368)	(6.0)	%
.16	Daniel Ash Management Project	2,210,005	2,186,808	23,197	1.1	%
.17	Smith Water Conservation	17,008	18,779	(1,771)	(9.4)	%
.18	Underground Fuel Tank Replacement	0	0	0	0.0	%
.19	Crist FDEP Agreement for Ozone Attainment	18,561,912	19,475,517	(913,605)	(4.7)	%
.20	Crist Stormwater Collection System	131,175	96,782	34,393	35.5	%
.21	Crist Common FTIR Monitor	8,352	8,705	(353)	(4.1)	%
.22	Precipitator Upgrades for CAM Compliance	2,096,283	2,069,395	26,888	1.3	%
.23	Plant Groundwater Investigation	0	24,082	(24,082)	(100.0)	%
.24	Crist Water Conservation	13,423	14,854	(1,431)	(9.6)	%
.25	Crist Condenser Tubes	821,670	1,112,260	(290,590)	(26.1)	%
.26	CAIR/CAMR/CAVR Compliance	2,273,939	3,539,882	(1,265,943)	(35.8)	%
.27	General Water Quality	1,673	4,092	(2,419)	(59.1)	%
.28	SO2 Allowances	2,019,015	2,159,886	(140,871)	36.0	%
2	Total Investment Projects - Recoverable Costs	33,857,505	36,627,609	(2,770,104)	(7.6)	%
3	Recoverable Costs Allocated to Energy	30,387,713	32,880,520	(2,492,807)	(7.6)	%
4	Recoverable Costs Allocated to Demand	3,469,792	3,747,089	(277,297)	(7.4)	%

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-06-0972-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 2007 - December 2007

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	4,295	4,270	4,245	4,220	4,195	4,172	4,147	4,122	4,097	4,073	4,048	4,023	49,907	0	49,907
	.2 Crist 5, 6 & 7 Precipitator Projects	170,187	169,714	169,240	168,768	168,295	167,822	167,349	166,876	166,404	165,930	165,457	164,985	2,011,027	0	2,011,027
	.3 Crist 7 Flue Gas Conditioning	14,091	14,090	14,087	14,086	14,083	14,082	14,080	14,078	14,076	14,074	14,072	14,070	168,969	0	168,969
	.4 Low NOx Burners, Crist 6 & 7	175,092	174,799	174,571	174,343	174,114	173,885	173,656	173,427	173,198	172,970	172,740	172,511	2,085,306	0	2,085,306
	.5 CEMS - Plants Crist, Scholz, Smith, & Daniel	64,022	63,910	63,798	63,685	63,582	63,419	63,245	63,670	64,890	65,509	65,544	65,645	770,919	0	770,919
	.6 Sub. Contam. Mobile Groundwater Treat. Sys.	9,004	8,988	8,970	8,954	8,935	8,918	8,901	8,883	8,866	8,848	8,831	8,810	106,908	98,684	8,224
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	2,417	2,411	2,405	2,400	2,395	2,389	2,383	2,377	2,371	2,367	2,361	2,355	28,631	26,429	2,202
	.8 Crist Cooling Tower Cell	6,893	6,870	6,846	6,821	6,934	7,230	6,308	5,214	5,212	5,211	5,210	5,207	73,956	68,267	5,689
	.9 Crist 1-5 Dechlorination	2,499	2,491	2,484	2,476	2,468	2,460	2,453	2,445	2,437	2,429	2,422	2,414	29,478	27,211	2,267
	.10 Crist Diesel Fuel Oil Remediation	624	622	621	618	617	615	613	612	610	608	606	605	7,371	6,803	568
	.11 Crist Bulk Tanker Unload Sec Contain Struc	832	829	827	824	822	819	817	814	812	809	806	804	9,815	9,060	755
	.12 Crist IWW Sampling System	485	484	481	480	479	477	476	475	472	471	470	468	5,718	5,278	440
	.13 Sodium Injection System	4,322	4,313	4,304	4,295	4,285	4,276	4,267	4,258	4,249	4,239	4,230	4,221	51,259	0	51,259
	.14 Smith Stormwater Collection System	22,548	22,494	22,439	22,386	22,330	22,274	22,220	22,165	22,111	22,056	22,002	21,947	266,972	246,437	20,535
	.15 Smith Waste Water Treatment Facility	3,087	3,083	3,081	3,076	3,074	3,070	3,065	3,063	3,059	3,055	3,053	3,048	36,814	33,980	2,834
	.16 Daniel Ash Management Project	186,656	186,244	185,860	185,479	184,913	184,406	183,971	183,479	182,988	182,495	182,003	181,511	2,210,005	2,040,005	170,000
	.17 Smith Water Conservation	1,431	1,429	1,427	1,423	1,422	1,418	1,416	1,414	1,412	1,407	1,406	1,403	17,008	15,698	1,310
	.18 Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.19 Crist FDEP Agreement for Ozone Attainment	1,556,128	1,552,420	1,548,787	1,554,972	1,557,779	1,551,192	1,547,969	1,544,321	1,541,122	1,538,395	1,535,899	1,532,928	18,561,912	0	18,561,912
	.20 Crist Stormwater Collection System	10,424	10,961	11,192	11,124	11,015	10,992	10,969	10,946	10,923	10,900	10,876	10,853	131,175	121,084	10,091
	.21 Crist Common FTIR Monitor	705	702	702	700	697	697	696	693	692	691	689	688	8,352	0	8,352
	.22 Precipitator Upgrades for CAM Compliance	114,010	118,163	125,120	140,055	162,137	175,387	177,731	185,941	198,041	211,918	232,309	255,471	2,096,283	0	2,096,283
	.23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 Crist Water Conservation	1,132	1,130	1,127	1,124	1,122	1,119	1,118	1,115	1,113	1,110	1,108	1,105	13,423	12,391	1,032
	.25 Crist Condenser Tubes	69,279	69,132	68,986	68,839	68,692	68,546	68,399	68,253	68,106	67,960	67,812	67,666	821,670	758,465	63,205
	.26 CAIR/CAMR/CAVR Compliance	315	827	1,378	1,845	5,858	173,710	338,501	339,307	340,477	343,146	357,528	371,047	2,273,939	0	2,273,939
	.27 General Water Quality	0	0	0	0	112	223	223	223	223	223	223	223	1,673	0	1,673
	.28 SO2 Allowances	156,165	216,944	207,847	199,858	190,009	178,848	169,085	158,592	148,553	139,364	131,062	122,688	2,019,015	0	2,019,015
2	Total Investment Projects - Recoverable Costs	2,576,643	2,637,320	2,630,825	2,642,851	2,660,364	2,822,446	2,974,058	2,966,763	2,966,514	2,970,258	2,992,767	3,016,696	33,857,505	3,469,792	30,387,713
3	Recoverable Costs Allocated to Energy	2,283,738	2,344,548	2,338,446	2,351,137	2,369,393	2,531,923	2,685,035	2,679,452	2,679,907	2,684,358	2,707,567	2,732,209	30,387,713		
4	Recoverable Costs Allocated to Demand	292,905	292,772	292,379	291,714	290,971	290,523	289,023	287,311	286,607	285,900	285,200	284,487	3,469,792		
5	Retail Energy Jurisdictional Factor	0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757			
6	Retail Demand Jurisdictional Factor	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872			
7	Jurisdictional Energy Recoverable Costs (B)	2,204,236	2,260,641	2,259,460	2,272,794	2,292,833	2,449,417	2,597,980	2,592,809	2,589,265	2,589,536	2,608,377	2,633,439	29,350,787		
8	Jurisdictional Demand Recoverable Costs (C)	283,089	282,960	282,581	281,938	281,220	280,787	279,337	277,682	277,002	276,319	275,642	274,953	3,353,510		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	2,487,325	2,543,601	2,542,041	2,554,732	2,574,053	2,730,204	2,877,317	2,870,491	2,866,267	2,865,855	2,884,019	2,908,392	32,704,297		

Notes:

(A) Pages 1-27 of Schedule 8E, Line 9, Page 28 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	
3	Less: Accumulated Depreciation (C)	(41,740)	(44,363)	(46,986)	(49,608)	(52,231)	(54,853)	(57,476)	(60,099)	(62,722)	(65,345)	(67,968)	(70,591)	(73,214)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	178,554	175,931	173,308	170,686	168,063	165,441	162,818	160,195	157,572	154,949	152,326	149,703	147,080	
6	Average Net Investment		177,243	174,620	171,997	169,375	166,752	164,130	161,507	158,884	156,261	153,638	151,015	148,392	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,302	1,283	1,264	1,244	1,225	1,206	1,187	1,167	1,148	1,129	1,110	1,090	14,355
	b Debt Component (Line 6 x Debt Component x 1/12)		370	364	359	353	348	343	337	332	326	321	315	310	4,078
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		2,623	2,623	2,622	2,623	2,622	2,623	2,623	2,623	2,623	2,623	2,623	2,623	31,474
	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)		4,295	4,270	4,245	4,220	4,195	4,172	4,147	4,122	4,097	4,073	4,048	4,023	49,907
	a Recoverable Costs Allocated to Energy		4,295	4,270	4,245	4,220	4,195	4,172	4,147	4,122	4,097	4,073	4,048	4,023	49,907
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		4,145	4,117	4,102	4,079	4,059	4,036	4,013	3,989	3,958	3,929	3,900	3,878	48,205
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)		4,145	4,117	4,102	4,079	4,059	4,036	4,013	3,989	3,958	3,929	3,900	3,878	48,205

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) PE 1244 7 year amorization; PE 1006 fully amortized
(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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1119, 1216, 1243, 1249
(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)	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	
3	Less: Accumulated Depreciation (C)	(1,781,062)	(1,831,194)	(1,881,326)	(1,931,458)	(1,981,590)	(2,031,722)	(2,081,854)	(2,131,986)	(2,182,118)	(2,232,250)	(2,282,382)	(2,332,514)	(2,382,646)	
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)	12,750,816	12,700,684	12,650,552	12,600,420	12,550,288	12,500,156	12,450,024	12,399,892	12,349,760	12,299,628	12,249,496	12,199,364	12,149,232	
6	Average Net Investment		12,725,750	12,675,618	12,625,486	12,575,354	12,525,222	12,475,090	12,424,958	12,374,826	12,324,694	12,274,562	12,224,430	12,174,298	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		93,496	93,128	92,759	92,391	92,023	91,654	91,286	90,918	90,550	90,181	89,813	89,445	1,097,644
	b Debt Component (Line 6 x Debt Component x 1/12)		26,559	26,454	26,349	26,245	26,140	26,036	25,931	25,826	25,722	25,617	25,512	25,408	311,799
8	Investment Expenses														
	a Depreciation (E)		38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	465,084
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	136,500
	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)		170,187	169,714	169,240	168,768	168,295	167,822	167,349	166,876	166,404	165,930	165,457	164,985	2,011,027
	a Recoverable Costs Allocated to Energy		170,187	169,714	169,240	168,768	168,295	167,822	167,349	166,876	166,404	165,930	165,457	164,985	2,011,027
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		164,262	163,640	163,524	163,145	162,857	162,353	161,923	161,480	160,776	160,069	159,396	159,021	1,942,446
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)		164,262	163,640	163,524	163,145	162,857	162,353	161,923	161,480	160,776	160,069	159,396	159,021	1,942,446

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) 3.2% 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 2007 - December 2007

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)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,472,159	1,471,955	1,471,751	1,471,547	1,471,343	1,471,139	1,470,935	1,470,731	1,470,527	1,470,323	1,470,119	1,469,915	1,469,711	
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)	1,472,159	1,471,955	1,471,751	1,471,547	1,471,343	1,471,139	1,470,935	1,470,731	1,470,527	1,470,323	1,470,119	1,469,915	1,469,711	
6	Average Net Investment		1,472,057	1,471,853	1,471,649	1,471,445	1,471,241	1,471,037	1,470,833	1,470,629	1,470,425	1,470,221	1,470,017	1,469,813	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,815	10,814	10,812	10,811	10,809	10,808	10,806	10,805	10,803	10,802	10,800	10,799	129,684
	b Debt Component (Line 6 x Debt Component x 1/12)		3,072	3,072	3,071	3,071	3,070	3,070	3,070	3,069	3,069	3,068	3,068	3,067	36,837
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		204	204	204	204	204	204	204	204	204	204	204	204	2,448
	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)		14,091	14,090	14,087	14,086	14,083	14,082	14,080	14,078	14,076	14,074	14,072	14,070	168,969
	a Recoverable Costs Allocated to Energy		14,091	14,090	14,087	14,086	14,083	14,082	14,080	14,078	14,076	14,074	14,072	14,070	168,969
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		13,600	13,586	13,611	13,617	13,628	13,623	13,623	13,623	13,600	13,577	13,556	13,561	163,205
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)		13,600	13,586	13,611	13,617	13,628	13,623	13,623	13,623	13,600	13,577	13,556	13,561	163,205

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) 3.2% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242, 1284
(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		589	208	(2)	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		589	208	(2)	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		(14,559)	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)	9,097,128	9,097,717	9,097,925	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	
3	Less: Accumulated Depreciation (C)	6,909,843	6,871,022	6,846,759	6,822,495	6,798,231	6,773,967	6,749,703	6,725,439	6,701,175	6,676,911	6,652,647	6,628,383	6,604,119	
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)	16,006,971	15,968,739	15,944,684	15,920,418	15,896,154	15,871,890	15,847,626	15,823,362	15,799,098	15,774,834	15,750,570	15,726,306	15,702,042	
6	Average Net Investment		15,987,855	15,956,712	15,932,551	15,908,286	15,884,022	15,859,758	15,835,494	15,811,230	15,786,966	15,762,702	15,738,438	15,714,174	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		117,463	117,234	117,056	116,878	116,700	116,522	116,343	116,165	115,987	115,809	115,630	115,452	1,397,239
	b Debt Component (Line 6 x Debt Component x 1/12)		33,367	33,302	33,251	33,201	33,150	33,099	33,049	32,998	32,947	32,897	32,846	32,795	396,902
8	Investment Expenses														
	a Depreciation (E)		24,262	24,263	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	291,165
	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)		175,092	174,799	174,571	174,343	174,114	173,885	173,656	173,427	173,198	172,970	172,740	172,511	2,085,306
	a Recoverable Costs Allocated to Energy		175,092	174,799	174,571	174,343	174,114	173,885	173,656	173,427	173,198	172,970	172,740	172,511	2,085,306
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		168,997	168,543	168,674	168,534	168,488	168,219	168,026	167,819	167,340	166,860	166,412	166,275	2,014,187
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)		168,997	168,543	168,674	168,534	168,488	168,219	168,026	167,819	167,340	166,860	166,412	166,275	2,014,187

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) 3.2% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist, Scholz, Smith, & Daniel
P.E.s 1154, 1164, 1217, 1240, 1245, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1364, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1558, 1570, 1658, 1829 & 1830
(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	1,848	66	0	113,527	152,919	0	44,877	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	43,238	0	0	0	
	c Retirements		0	0	0	0	0	47,553	0	0	0	50,652	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	4,000	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	4,346,031	4,346,031	4,346,031	4,346,031	4,346,031	4,346,031	4,298,478	4,298,478	4,298,478	4,341,716	4,291,064	4,291,064	4,291,064	
3	Less: Accumulated Depreciation (C)	1,044,072	1,032,178	1,020,284	1,008,390	996,496	984,602	1,020,322	1,008,551	996,780	988,953	1,027,788	1,016,036	1,004,284	
4	CWIP - Non Interest Bearing	0	0	0	0	0	1,848	1,914	1,914	115,441	225,122	225,122	269,999	269,999	
5	Net Investment (Lines 2 + 3 + 4)	5,390,103	5,378,209	5,366,315	5,354,421	5,342,527	5,332,481	5,320,714	5,308,943	5,410,699	5,555,791	5,543,974	5,577,099	5,565,347	
6	Average Net Investment		5,384,156	5,372,262	5,360,368	5,348,474	5,337,504	5,326,598	5,314,829	5,359,821	5,483,245	5,549,883	5,560,537	5,571,223	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		39,557	39,470	39,383	39,295	39,215	39,135	39,048	39,379	40,285	40,775	40,853	40,932	477,327
	b Debt Component (Line 6 x Debt Component x 1/12)		11,237	11,212	11,187	11,162	11,139	11,117	11,092	11,186	11,444	11,583	11,605	11,627	135,591
8	Investment Expenses														
	a Depreciation (E)		11,762	11,762	11,762	11,762	11,762	11,701	11,639	11,639	11,695	11,685	11,620	11,620	140,409
	b Amortization (F)		132	132	132	132	132	132	132	132	132	132	132	132	1,584
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	16,008
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		64,022	63,910	63,798	63,685	63,582	63,419	63,245	63,670	64,890	65,509	65,544	65,645	770,919
	a Recoverable Costs Allocated to Energy		64,022	63,910	63,798	63,685	63,582	63,419	63,245	63,670	64,890	65,509	65,544	65,645	770,919
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		61,793	61,623	61,643	61,563	61,528	61,352	61,194	61,611	62,695	63,195	63,143	63,272	744,612
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)		61,793	61,623	61,643	61,563	61,528	61,352	61,194	61,611	62,695	63,195	63,143	63,272	744,612

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $2,232,602; Scholz $790,064; Smith $688,899; Daniel $634,465. Ending Balances: Crist, $2,232,602; Scholz $790,064; Smith $688,899; Daniel $579,498.
(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: 3.2%; Smith 2.5%; Scholz 4.2%; Daniel 3.1% annually
(F) PE 1364 & 1658 have a 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 2007 - December 2007

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)	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	
3	Less: Accumulated Depreciation (C)	(157,270)	(159,106)	(160,941)	(162,777)	(164,614)	(166,449)	(168,285)	(170,121)	(171,957)	(173,793)	(175,629)	(177,465)	(179,301)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	760,754	758,918	757,083	755,247	753,410	751,575	749,739	747,903	746,067	744,231	742,395	740,559	738,723	
6	Average Net Investment		759,837	758,001	756,166	754,329	752,493	750,658	748,822	746,986	745,150	743,314	741,478	739,642	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,583	5,569	5,556	5,542	5,529	5,515	5,502	5,488	5,475	5,461	5,448	5,434	66,102
	b Debt Component (Line 6 x Debt Component x 1/12)		1,586	1,582	1,578	1,574	1,570	1,567	1,563	1,559	1,555	1,551	1,547	1,544	18,776
8	Investment Expenses														
	a Depreciation (E)		1,836	1,835	1,836	1,837	1,835	1,836	1,836	1,836	1,836	1,836	1,836	1,836	22,031
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		9,004	8,988	8,970	8,954	8,935	8,918	8,901	8,883	8,866	8,848	8,831	8,810	106,909
	a Recoverable Costs Allocated to Energy		692	691	690	689	688	686	684	683	683	681	679	678	8,224
	b Recoverable Costs Allocated to Demand		8,312	8,297	8,280	8,265	8,247	8,232	8,217	8,200	8,183	8,167	8,152	8,132	98,684
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		668	666	667	666	666	664	662	661	660	657	654	653	7,944
13	Retail Demand-Related Recoverable Costs (I)		8,033	8,019	8,003	7,988	7,971	7,956	7,942	7,925	7,909	7,893	7,879	7,859	95,377
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,701	8,685	8,670	8,654	8,637	8,620	8,604	8,586	8,569	8,550	8,533	8,512	103,321

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 2.4% annually, PEs 3400 and 3412 depreciable at 2.4% annually
(F) The amortizable portion of PE 1007 is fully amortized
(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 2007 - December 2007

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 (C)	(49,444)	(50,038)	(50,632)	(51,226)	(51,820)	(52,414)	(53,008)	(53,602)	(54,196)	(54,790)	(55,384)	(55,978)	(56,572)	
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)	193,499	192,905	192,311	191,717	191,123	190,529	189,935	189,341	188,747	188,153	187,559	186,965	186,371	
6	Average Net Investment		193,202	192,608	192,014	191,420	190,826	190,232	189,638	189,044	188,450	187,856	187,262	186,668	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,419	1,415	1,411	1,406	1,402	1,398	1,393	1,389	1,385	1,380	1,376	1,371	16,745
	b Debt Component (Line 6 x Debt Component x 1/12)		403	402	401	399	398	397	396	395	393	392	391	390	4,757
8	Investment Expenses														
	a Depreciation (E)		594	594	594	594	594	594	594	594	594	594	594	594	7,129
	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)		2,417	2,411	2,405	2,400	2,395	2,389	2,383	2,377	2,371	2,367	2,361	2,355	28,631
	a Recoverable Costs Allocated to Energy		186	185	185	185	184	184	184	183	182	182	181	181	2,202
	b Recoverable Costs Allocated to Demand		2,231	2,226	2,220	2,215	2,211	2,205	2,199	2,194	2,189	2,185	2,180	2,174	26,429
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		180	178	179	179	178	178	178	177	176	176	174	174	2,127
13	Retail Demand-Related Recoverable Costs (I)		2,156	2,151	2,146	2,141	2,137	2,131	2,125	2,120	2,116	2,112	2,107	2,101	25,543
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,336	2,329	2,325	2,320	2,315	2,309	2,303	2,297	2,292	2,288	2,281	2,275	27,670

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,920 and Smith $93,023.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.2%; Smith 2.5% 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 2007 - December 2007

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	906,659	0	0	0	0	0	
	d Cost of Removal		0	0	0	103	40,517	39,496	25,923	0	0	0	0	0	
	e Salvage		0	0	0	0	11,552	631	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	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	(448,111)	(450,691)	(453,271)	(455,851)	(458,328)	(431,943)	(395,658)	535,553	535,391	535,229	535,067	534,905	534,743	
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)	458,548	455,968	453,388	450,808	448,331	474,716	511,001	535,553	535,391	535,229	535,067	534,905	534,743	
6	Average Net Investment		457,258	454,678	452,098	449,570	461,524	492,859	523,277	535,472	535,310	535,148	534,986	534,824	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,359	3,341	3,322	3,303	3,391	3,621	3,845	3,934	3,933	3,932	3,931	3,929	43,841
	b Debt Component (Line 6 x Debt Component x 1/12)		954	949	944	938	963	1,029	1,092	1,118	1,117	1,117	1,117	1,116	12,454
8	Investment Expenses														
	a Depreciation (E)		2,418	2,418	2,418	2,418	2,418	2,418	1,209	0	0	0	0	0	15,717
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		162	162	162	162	162	162	162	162	162	162	162	162	1,944
	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)		6,893	6,870	6,846	6,821	6,934	7,230	6,308	5,214	5,212	5,211	5,210	5,207	73,956
	a Recoverable Costs Allocated to Energy		530	528	527	525	533	556	485	401	401	401	401	401	5,689
	b Recoverable Costs Allocated to Demand		6,363	6,342	6,319	6,296	6,401	6,674	5,823	4,813	4,811	4,810	4,809	4,806	68,267
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		512	509	509	508	516	538	469	388	387	387	386	387	5,496
13	Retail Demand-Related Recoverable Costs (I)		6,150	6,129	6,107	6,085	6,186	6,450	5,628	4,652	4,650	4,649	4,648	4,645	65,979
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		6,662	6,638	6,616	6,593	6,702	6,988	6,097	5,040	5,037	5,036	5,034	5,032	71,475

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) 3.2% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 1-5 Dechlorination
P.E. 1248
(in Dollars)

Line	Description	Beginning of Period Amoun	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	
3	Less: Accumulated Depreciation (C)	(126,316)	(127,130)	(127,944)	(128,759)	(129,573)	(130,387)	(131,201)	(132,015)	(132,829)	(133,643)	(134,457)	(135,271)	(136,085)	
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)	179,007	178,193	177,379	176,564	175,750	174,936	174,122	173,308	172,494	171,680	170,866	170,052	169,238	
6	Average Net Investment		178,600	177,786	176,972	176,157	175,343	174,529	173,715	172,901	172,087	171,273	170,459	169,645	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,312	1,306	1,300	1,294	1,288	1,282	1,276	1,270	1,264	1,258	1,252	1,246	15,348
	b Debt Component (Line 6 x Debt Component x 1/12)		373	371	369	368	366	364	363	361	359	357	356	354	4,361
8	Investment Expenses														
	a Depreciation (E)		814	814	815	814	814	814	814	814	814	814	814	814	9,769
	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)		2,499	2,491	2,484	2,476	2,468	2,460	2,453	2,445	2,437	2,429	2,422	2,414	29,478
	a Recoverable Costs Allocated to Energy		192	192	191	190	190	189	189	188	187	187	186	186	2,267
	b Recoverable Costs Allocated to Demand		2,307	2,299	2,293	2,286	2,278	2,271	2,264	2,257	2,250	2,242	2,236	2,228	27,211
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		185	185	185	184	184	183	183	182	181	180	179	179	2,190
13	Retail Demand-Related Recoverable Costs (I)		2,230	2,222	2,216	2,209	2,202	2,195	2,188	2,181	2,175	2,167	2,161	2,153	26,299
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,415	2,407	2,401	2,393	2,386	2,378	2,371	2,363	2,356	2,347	2,340	2,332	28,489

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) 3.2% 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 2007 - December 2007

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)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(22,213)	(22,397)	(22,581)	(22,765)	(22,949)	(23,133)	(23,317)	(23,501)	(23,685)	(23,869)	(24,053)	(24,237)	(24,421)	
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)	46,710	46,526	46,342	46,158	45,974	45,790	45,606	45,422	45,238	45,054	44,870	44,686	44,502	
6	Average Net Investment		46,618	46,434	46,250	46,066	45,882	45,698	45,514	45,330	45,146	44,962	44,778	44,594	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		343	341	340	338	337	336	334	333	332	330	329	328	4,021
	b Debt Component (Line 6 x Debt Component x 1/12)		97	97	97	96	96	95	95	95	94	94	93	93	1,142
8	Investment Expenses														
	a Depreciation (E)		184	184	184	184	184	184	184	184	184	184	184	184	2,208
	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)		624	622	621	618	617	615	613	612	610	608	606	605	7,371
	a Recoverable Costs Allocated to Energy		48	48	48	48	47	47	47	47	47	47	47	47	568
	b Recoverable Costs Allocated to Demand		576	574	573	570	570	568	566	565	563	561	559	558	6,803
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		46	46	46	46	45	45	45	45	45	45	45	45	544
13	Retail Demand-Related Recoverable Costs (I)		557	555	554	551	551	549	547	546	544	542	540	539	6,575
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		603	601	600	597	596	594	592	591	589	587	585	584	7,119

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) 3.2% 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 2007 - December 2007

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 (C)	(41,922)	(42,193)	(42,464)	(42,735)	(43,006)	(43,277)	(43,548)	(43,819)	(44,090)	(44,361)	(44,632)	(44,903)	(45,174)	
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)	59,573	59,302	59,031	58,760	58,489	58,218	57,947	57,676	57,405	57,134	56,863	56,592	56,321	
6	Average Net Investment		59,438	59,167	58,896	58,625	58,354	58,083	57,812	57,541	57,270	56,999	56,728	56,457	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		437	435	433	431	429	427	425	423	421	419	417	415	5,112
	b Debt Component (Line 6 x Debt Component x 1/12)		124	123	123	122	122	121	121	120	120	119	118	118	1,451
8	Investment Expenses														
	a Depreciation (E)		271	271	271	271	271	271	271	271	271	271	271	271	3,252
	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)		832	829	827	824	822	819	817	814	812	809	806	804	9,815
	a Recoverable Costs Allocated to Energy		64	64	64	63	63	63	63	63	62	62	62	62	755
	b Recoverable Costs Allocated to Demand		768	765	763	761	759	756	754	751	750	747	744	742	9,060
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		62	62	62	61	61	61	61	61	60	60	60	60	731
13	Retail Demand-Related Recoverable Costs (I)		742	739	737	735	734	731	729	726	725	722	719	717	8,756
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		804	801	799	796	795	792	790	787	785	782	779	777	9,487

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.2% 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 2007 - December 2007

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 (C)	(24,922)	(25,081)	(25,240)	(25,399)	(25,558)	(25,717)	(25,876)	(26,035)	(26,194)	(26,353)	(26,512)	(26,671)	(26,830)	
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)	34,621	34,462	34,303	34,144	33,985	33,826	33,667	33,508	33,349	33,190	33,031	32,872	32,713	
6	Average Net Investment		34,542	34,383	34,224	34,065	33,906	33,747	33,588	33,429	33,270	33,111	32,952	32,793	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		254	253	251	250	249	248	247	246	244	243	242	241	2,968
	b Debt Component (Line 6 x Debt Component x 1/12)		72	72	71	71	71	70	70	70	69	69	69	68	842
8	Investment Expenses														
	a Depreciation (E)		159	159	159	159	159	159	159	159	159	159	159	159	1,908
	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	484	481	480	479	477	476	475	472	471	470	468	5,718
	a Recoverable Costs Allocated to Energy		37	37	37	37	37	37	37	37	36	36	36	36	440
	b Recoverable Costs Allocated to Demand		448	447	444	443	442	440	439	438	436	435	434	432	5,278
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		36	36	36	36	36	36	36	36	35	35	35	35	428
13	Retail Demand-Related Recoverable Costs (I)		433	432	429	428	427	425	424	423	421	420	419	418	5,099
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		469	468	465	464	463	461	460	459	456	455	454	453	5,527

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) 3.2% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214 & 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)	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	
3	Less: Accumulated Depreciation (C)	(36,445)	(37,426)	(38,407)	(39,388)	(40,369)	(41,350)	(42,331)	(43,312)	(44,293)	(45,274)	(46,255)	(47,236)	(48,217)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	354,674	353,693	352,712	351,731	350,750	349,769	348,788	347,807	346,826	345,845	344,864	343,883	342,902	
6	Average Net Investment		354,184	353,203	352,222	351,241	350,260	349,279	348,298	347,317	346,336	345,355	344,374	343,393	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,602	2,595	2,588	2,581	2,573	2,566	2,559	2,552	2,545	2,537	2,530	2,523	30,751
	b Debt Component (Line 6 x Debt Component x 1/12)		739	737	735	733	731	729	727	725	723	721	719	717	8,736
8	Investment Expenses														
	a Depreciation (E)		981	981	981	981	981	981	981	981	981	981	981	981	11,772
	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)		4,322	4,313	4,304	4,295	4,285	4,276	4,267	4,258	4,249	4,239	4,230	4,221	51,259
	a Recoverable Costs Allocated to Energy		4,322	4,313	4,304	4,295	4,285	4,276	4,267	4,258	4,249	4,239	4,230	4,221	51,259
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		4,172	4,159	4,159	4,152	4,147	4,137	4,129	4,120	4,105	4,089	4,075	4,068	49,512
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)		4,172	4,159	4,159	4,152	4,147	4,137	4,129	4,120	4,105	4,089	4,075	4,068	49,512

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $284,622 and Smith $106,497.
(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 3.2% annually; Smith 2.5% 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 2007 - December 2007

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)	(1,003,963)	(1,009,759)	(1,015,555)	(1,021,351)	(1,027,148)	(1,032,944)	(1,038,740)	(1,044,536)	(1,050,332)	(1,056,128)	(1,061,924)	(1,067,720)	(1,073,516)	
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)	1,778,637	1,772,841	1,767,045	1,761,249	1,755,452	1,749,656	1,743,860	1,738,064	1,732,268	1,726,472	1,720,676	1,714,880	1,709,084	
6	Average Net Investment		1,775,739	1,769,943	1,764,147	1,758,351	1,752,554	1,746,758	1,740,962	1,735,166	1,729,370	1,723,574	1,717,778	1,711,982	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		13,046	13,004	12,961	12,919	12,876	12,833	12,791	12,748	12,706	12,663	12,621	12,578	153,746
	b Debt Component (Line 6 x Debt Component x 1/12)		3,706	3,694	3,682	3,670	3,658	3,645	3,633	3,621	3,609	3,597	3,585	3,573	43,673
8	Investment Expenses														
	a Depreciation (E)		5,796	5,796	5,796	5,797	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	69,553
	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)		22,548	22,494	22,439	22,386	22,330	22,274	22,220	22,165	22,111	22,056	22,002	21,947	266,972
	a Recoverable Costs Allocated to Energy		1,734	1,730	1,726	1,722	1,718	1,713	1,709	1,705	1,701	1,697	1,692	1,688	20,535
	b Recoverable Costs Allocated to Demand		20,814	20,764	20,713	20,664	20,612	20,561	20,511	20,460	20,410	20,359	20,310	20,259	246,437
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		1,674	1,668	1,668	1,665	1,662	1,657	1,654	1,650	1,643	1,637	1,630	1,627	19,835
13	Retail Demand-Related Recoverable Costs (I)		20,116	20,068	20,019	19,971	19,921	19,872	19,824	19,774	19,726	19,677	19,629	19,580	238,177
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		21,790	21,736	21,687	21,636	21,583	21,529	21,478	21,424	21,369	21,314	21,259	21,207	258,012

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) 2.5% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E. 1466 & 1643
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	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)	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	
3	Less: Accumulated Depreciation (C)	108,949	108,576	108,204	107,831	107,458	107,085	106,712	106,339	105,966	105,593	105,220	104,847	104,474	
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)	287,911	287,538	287,166	286,793	286,420	286,047	285,674	285,301	284,928	284,555	284,182	283,809	283,436	
6	Average Net Investment		287,725	287,352	286,980	286,607	286,234	285,861	285,488	285,115	284,742	284,369	283,996	283,623	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,114	2,111	2,108	2,106	2,103	2,100	2,097	2,095	2,092	2,089	2,087	2,084	25,186
	b Debt Component (Line 6 x Debt Component x 1/12)		600	600	599	598	597	597	596	595	594	593	593	592	7,154
8	Investment Expenses														
	a Depreciation (E)		373	372	373	373	373	373	373	373	373	373	373	373	4,474
	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)		3,087	3,083	3,081	3,076	3,074	3,070	3,065	3,063	3,059	3,055	3,053	3,048	36,814
	a Recoverable Costs Allocated to Energy		237	237	237	237	237	236	236	236	236	235	235	235	2,834
	b Recoverable Costs Allocated to Demand		2,850	2,846	2,844	2,839	2,837	2,834	2,829	2,827	2,823	2,820	2,818	2,813	33,980
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		229	229	229	229	229	228	228	228	228	227	226	227	2,737
13	Retail Demand-Related Recoverable Costs (I)		2,754	2,751	2,749	2,744	2,742	2,739	2,734	2,732	2,728	2,725	2,724	2,719	32,841
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,983	2,980	2,978	2,973	2,971	2,967	2,962	2,960	2,956	2,952	2,950	2,946	35,578

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) Smith 2.5% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E. 1535, 1555, & 1819
(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		13,258	(3,123)	18,743	(434)	(12,536)	9,089	0	0	0	0	0	0	
	b Clearings to Plant		13,258	(3,123)	18,743	(434)	(12,536)	9,089	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		921	2,952	44	261	714	473	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)	16,178,324	16,191,582	16,188,459	16,207,202	16,206,768	16,194,232	16,203,321	16,203,321	16,203,321	16,203,321	16,203,321	16,203,321	16,203,321	
3	Less: Accumulated Depreciation (C)	(5,280,222)	(5,331,418)	(5,380,597)	(5,432,704)	(5,484,617)	(5,536,060)	(5,587,740)	(5,639,905)	(5,692,070)	(5,744,235)	(5,796,400)	(5,848,565)	(5,900,730)	
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)	10,898,102	10,860,164	10,807,862	10,774,498	10,722,151	10,658,172	10,615,581	10,563,416	10,511,251	10,459,086	10,406,921	10,354,756	10,302,591	
6	Average Net Investment		10,879,133	10,834,013	10,791,180	10,748,325	10,690,162	10,636,877	10,589,499	10,537,334	10,485,169	10,433,004	10,380,839	10,328,674	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		79,929	79,597	79,283	78,968	78,541	78,149	77,801	77,418	77,035	76,651	76,268	75,885	935,525
	b Debt Component (Line 6 x Debt Component x 1/12)		22,705	22,611	22,521	22,432	22,310	22,199	22,100	21,991	21,883	21,774	21,665	21,556	265,747
8	Investment Expenses														
	a Depreciation (E)		41,805	41,819	41,839	41,862	41,845	41,841	41,853	41,853	41,853	41,853	41,853	41,853	502,129
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	123,744
	d Property Taxes		31,905	31,905	31,905	31,905	31,905	31,905	31,905	31,905	31,905	31,905	31,905	31,905	382,860
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		186,656	186,244	185,860	185,479	184,913	184,406	183,971	183,479	182,988	182,495	182,003	181,511	2,210,005
	a Recoverable Costs Allocated to Energy		14,358	14,326	14,297	14,268	14,224	14,185	14,152	14,114	14,076	14,038	14,000	13,962	170,000
	b Recoverable Costs Allocated to Demand		172,298	171,918	171,563	171,211	170,689	170,221	169,819	169,365	168,912	168,457	168,003	167,549	2,040,005
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		13,858	13,813	13,814	13,793	13,764	13,723	13,693	13,658	13,600	13,542	13,487	13,457	164,202
13	Retail Demand-Related Recoverable Costs (I)		166,524	166,157	165,813	165,473	164,969	164,516	164,128	163,689	163,251	162,812	162,373	161,934	1,971,639
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		180,382	179,970	179,627	179,266	178,733	178,239	177,821	177,347	176,851	176,354	175,860	175,391	2,135,841

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) 3.1% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 1620, 1638
(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)	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	
3	Less: Accumulated Depreciation (C)	(11,862)	(12,141)	(12,421)	(12,700)	(12,979)	(13,259)	(13,538)	(13,818)	(14,098)	(14,378)	(14,658)	(14,938)	(15,218)	
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)	122,273	121,994	121,714	121,435	121,156	120,876	120,597	120,317	120,037	119,757	119,477	119,197	118,917	
6	Average Net Investment		122,133	121,854	121,575	121,295	121,016	120,736	120,457	120,177	119,897	119,617	119,337	119,057	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		897	895	894	891	889	887	885	883	881	878	877	875	10,632
	b Debt Component (Line 6 x Debt Component x 1/12)		255	254	254	253	253	252	251	251	251	249	249	248	3,020
8	Investment Expenses														
	a Depreciation (E)		279	280	279	279	280	279	280	280	280	280	280	280	3,356
	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)		1,431	1,429	1,427	1,423	1,422	1,418	1,416	1,414	1,412	1,407	1,406	1,403	17,008
	a Recoverable Costs Allocated to Energy		110	110	110	109	109	109	109	109	109	109	109	108	1,310
	b Recoverable Costs Allocated to Demand		1,321	1,319	1,317	1,314	1,313	1,309	1,307	1,305	1,303	1,298	1,297	1,295	15,698
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		106	106	106	105	105	105	105	105	105	105	105	104	1,262
13	Retail Demand-Related Recoverable Costs (I)		1,277	1,275	1,273	1,270	1,269	1,265	1,263	1,261	1,259	1,255	1,254	1,252	15,173
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,383	1,381	1,379	1,375	1,374	1,370	1,368	1,366	1,364	1,360	1,359	1,356	16,435

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) 2.5% 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 2007 - December 2007

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)	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 (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component 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		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional 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
(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) PE 4397 fully amortized.
(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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E. 1031, 1199, 1250, 1287
(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		(13,909)	1,529	2,631	1,524,890	(112,577)	74,066	0	0	95,473	100,000	60,000	0	
	b Clearings to Plant		23,234	1,529	0	1,921,141	(124,234)	57,185	0	0	0	0	300,000	0	
	c Retirements		0	0	0	0	1,921,077	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	19,918	(19,918)	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)	133,801,191	133,824,425	133,825,954	133,825,954	135,747,095	133,701,784	133,758,969	133,758,969	133,758,969	133,758,969	133,758,969	134,058,969	134,058,969	
3	Less: Accumulated Depreciation (C)	(10,115,423)	(10,502,400)	(10,889,378)	(11,276,354)	(11,645,960)	(10,134,144)	(10,520,836)	(10,907,605)	(11,294,374)	(11,681,143)	(12,067,912)	(12,455,081)	(12,842,650)	
4	CWIP - Non Interest Bearing	444,220	407,077	407,077	409,708	13,457	25,114	41,995	41,995	41,995	137,468	237,468	(2,532)	(2,532)	
5	Net Investment (Lines 2 + 3 + 4)	124,129,988	123,729,102	123,343,653	122,959,308	124,114,592	123,592,754	123,280,128	122,893,359	122,506,590	122,215,294	121,928,525	121,601,356	121,213,787	
6	Average Net Investment		123,929,545	123,536,378	123,151,481	123,536,950	123,853,673	123,436,441	123,086,744	122,699,975	122,360,942	122,071,910	121,764,941	121,407,572	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		910,510	907,622	904,794	907,626	909,953	906,888	904,318	901,477	898,986	896,862	894,607	891,981	10,835,624
	b Debt Component (Line 6 x Debt Component x 1/12)		258,641	257,820	257,017	257,822	258,483	257,612	256,882	256,075	255,367	254,764	254,123	253,378	3,077,984
8	Investment Expenses														
	a Depreciation (E)		356,430	356,431	356,429	358,977	358,796	356,145	356,222	356,222	356,222	356,222	356,622	357,022	4,281,740
	b Amortization (F)		1,867	1,867	1,867	1,867	1,867	1,867	1,867	1,867	1,867	1,867	1,867	1,867	22,404
	c Dismantlement		28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	344,160
	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)		1,556,128	1,552,420	1,548,787	1,554,972	1,557,779	1,551,192	1,547,969	1,544,321	1,541,122	1,538,395	1,535,899	1,532,928	18,561,912
	a Recoverable Costs Allocated to Energy		1,556,128	1,552,420	1,548,787	1,554,972	1,557,779	1,551,192	1,547,969	1,544,321	1,541,122	1,538,395	1,535,899	1,532,928	18,561,912
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		1,501,956	1,496,862	1,496,473	1,503,158	1,507,444	1,500,644	1,497,780	1,494,384	1,488,997	1,484,053	1,479,632	1,477,513	17,928,896
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)		1,501,956	1,496,862	1,496,473	1,503,158	1,507,444	1,500,644	1,497,780	1,494,384	1,488,997	1,484,053	1,479,632	1,477,513	17,928,896

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: 3.2% annually
(F) Portions of 1287 have 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Stormwater Collection System
P.E. 1272
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		57,505	35,087	6,914	(14,196)	0	0	0	0	0	0	0	0	
	b Clearings to Plant		57,505	35,087	6,914	(14,196)	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)	834,527	892,032	927,119	934,033	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	
3	Less: Accumulated Depreciation (C)	(1,321)	(3,624)	(6,050)	(8,532)	(11,004)	(13,457)	(15,910)	(18,363)	(20,816)	(23,269)	(25,722)	(28,175)	(30,628)	
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)	833,206	888,408	921,069	925,501	908,833	906,380	903,927	901,474	899,021	896,568	894,115	891,662	889,209	
6	Average Net Investment		860,807	904,739	923,285	917,167	907,607	905,154	902,701	900,248	897,795	895,342	892,889	890,436	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,324	6,647	6,783	6,738	6,668	6,650	6,632	6,614	6,596	6,578	6,560	6,542	79,332
	b Debt Component (Line 6 x Debt Component x 1/12)		1,797	1,888	1,927	1,914	1,894	1,889	1,884	1,879	1,874	1,869	1,863	1,858	22,536
8	Investment Expenses														
	a Depreciation (E)		2,303	2,426	2,482	2,472	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	29,307
	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)		10,424	10,961	11,192	11,124	11,015	10,992	10,969	10,946	10,923	10,900	10,876	10,853	131,175
	a Recoverable Costs Allocated to Energy		802	843	861	856	847	846	844	842	840	838	837	835	10,091
	b Recoverable Costs Allocated to Demand		9,622	10,118	10,331	10,268	10,168	10,146	10,125	10,104	10,083	10,062	10,039	10,018	121,084
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		774	813	832	827	820	818	817	815	812	808	806	805	9,747
13	Retail Demand-Related Recoverable Costs (I)		9,300	9,779	9,985	9,924	9,827	9,806	9,786	9,765	9,745	9,725	9,703	9,682	117,027
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,074	10,592	10,817	10,751	10,647	10,624	10,603	10,580	10,557	10,533	10,509	10,487	126,774

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) 3.2% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	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)	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	
3	Less: Accumulated Depreciation (C)	(5,883)	(6,051)	(6,218)	(6,386)	(6,554)	(6,721)	(6,889)	(7,057)	(7,225)	(7,393)	(7,561)	(7,729)	(7,897)	
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)	56,987	56,819	56,652	56,484	56,316	56,149	55,981	55,813	55,645	55,477	55,309	55,141	54,973	
6	Average Net Investment		56,903	56,736	56,568	56,400	56,233	56,065	55,897	55,729	55,561	55,393	55,225	55,057	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		418	417	416	414	413	412	411	409	408	407	406	405	4,936
	b Debt Component (Line 6 x Debt Component x 1/12)		119	118	118	118	117	117	117	116	116	116	115	115	1,402
8	Investment Expenses														
	a Depreciation (E)		168	167	168	168	167	168	168	168	168	168	168	168	2,014
	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)		705	702	702	700	697	697	696	693	692	691	689	688	8,352
	a Recoverable Costs Allocated to Energy		705	702	702	700	697	697	696	693	692	691	689	688	8,352
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		680	677	678	677	674	674	673	671	669	667	664	663	8,067
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)		680	677	678	677	674	674	673	671	669	667	664	663	8,067

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) 3.2% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E. 1175, 1191, 1305, 1461, 1462
(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		533,151	375,092	1,128,557	2,065,915	728,411	176,006	350,000	1,455,762	1,174,817	1,832,342	2,555,872	701,281	
	b Clearings to Plant		0	0	0	0	8,715,023	164,586	0	0	0	0	0	6,060,708	
	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)	6,808,119	6,808,119	6,808,119	6,808,119	6,808,119	15,523,142	15,687,728	15,687,728	15,687,728	15,687,728	15,687,728	15,687,728	21,748,436	
3	Less: Accumulated Depreciation (C)	(392,470)	(406,651)	(420,833)	(435,014)	(449,195)	(472,454)	(504,960)	(537,637)	(570,314)	(602,991)	(635,668)	(668,345)	(709,167)	
4	CWIP - Non Interest Bearing	3,906,778	4,439,929	4,815,021	5,943,578	8,009,493	22,881	34,301	384,301	1,840,063	3,014,880	4,847,222	7,403,094	2,043,667	
5	Net Investment (Lines 2 + 3 + 4)	10,322,427	10,841,397	11,202,307	12,316,683	14,368,417	15,073,569	15,217,069	15,534,392	16,957,477	18,099,617	19,899,282	22,422,477	23,082,936	
6	Average Net Investment		10,581,912	11,021,852	11,759,495	13,342,550	14,720,993	15,145,319	15,375,731	16,245,935	17,528,547	18,999,450	21,160,880	22,752,707	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		77,745	80,978	86,397	98,028	108,155	111,273	112,965	119,359	128,782	139,589	155,469	167,164	1,385,904
	b Debt Component (Line 6 x Debt Component x 1/12)		22,084	23,003	24,542	27,846	30,723	31,608	32,089	33,905	36,582	39,652	44,163	47,485	393,682
8	Investment Expenses														
	a Depreciation (E)		14,181	14,182	14,181	14,181	23,259	32,506	32,677	32,677	32,677	32,677	32,677	40,822	316,697
	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)		114,010	118,163	125,120	140,055	162,137	175,387	177,731	185,941	198,041	211,918	232,309	255,471	2,096,283
	a Recoverable Costs Allocated to Energy		114,010	118,163	125,120	140,055	162,137	175,387	177,731	185,941	198,041	211,918	232,309	255,471	2,096,283
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		110,041	113,934	120,894	135,388	156,898	169,672	171,969	179,928	191,343	204,432	223,799	246,236	2,024,534
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)		110,041	113,934	120,894	135,388	156,898	169,672	171,969	179,928	191,343	204,432	223,799	246,236	2,024,534

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $0; Smith $6,808,119; Scholz $0. Ending Balances: Crist, $5,910,708; Smith $15,687,728; Scholz $150,000.
(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 3.2%; Smith 2.5%; Scholz 4.2% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E. 1218 & 1361
(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)	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 (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component 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		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional 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
(B) Beginning Balances: Crist $0; Scholz $0. Ending Balances: Crist, $0; Scholz $0.
(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 3.2% annually; Scholz 4.2% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Water Conservation Project
P.E. 1227
(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)	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	
3	Less: Accumulated Depreciation (C)	(148)	(398)	(648)	(898)	(1,148)	(1,398)	(1,648)	(1,898)	(2,148)	(2,398)	(2,648)	(2,898)	(3,148)	
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)	93,587	93,337	93,087	92,837	92,587	92,337	92,087	91,837	91,587	91,337	91,087	90,837	90,587	
6	Average Net Investment		93,462	93,212	92,962	92,712	92,462	92,212	91,962	91,712	91,462	91,212	90,962	90,712	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		687	685	683	681	679	677	676	674	672	670	668	666	8,118
	b Debt Component (Line 6 x Debt Component x 1/12)		195	195	194	193	193	192	192	191	191	190	190	189	2,305
8	Investment Expenses														
	a Depreciation (E)		250	250	250	250	250	250	250	250	250	250	250	250	3,000
	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)		1,132	1,130	1,127	1,124	1,122	1,119	1,118	1,115	1,113	1,110	1,108	1,105	13,423
	a Recoverable Costs Allocated to Energy		87	87	87	86	86	86	86	86	86	85	85	85	1,032
	b Recoverable Costs Allocated to Demand		1,045	1,043	1,040	1,038	1,036	1,033	1,032	1,029	1,027	1,025	1,023	1,020	12,391
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		84	84	84	83	83	83	83	83	83	82	82	82	996
13	Retail Demand-Related Recoverable Costs (I)		1,010	1,008	1,005	1,003	1,001	998	997	995	993	991	989	986	11,976
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,094	1,092	1,089	1,086	1,084	1,081	1,080	1,078	1,076	1,073	1,071	1,068	12,972

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) 3.2% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Condenser Tubes
P.E. 1204
(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)	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	
3	Less: Accumulated Depreciation (C)	(123,837)	(139,379)	(154,921)	(170,463)	(186,005)	(201,547)	(217,089)	(232,631)	(248,173)	(263,715)	(279,257)	(294,799)	(310,341)	
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)	5,703,870	5,688,328	5,672,786	5,657,244	5,641,702	5,626,160	5,610,618	5,595,076	5,579,534	5,563,992	5,548,450	5,532,908	5,517,366	
6	Average Net Investment		5,696,099	5,680,557	5,665,015	5,649,473	5,633,931	5,618,389	5,602,847	5,587,305	5,571,763	5,556,221	5,540,679	5,525,137	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		41,849	41,735	41,621	41,507	41,392	41,278	41,164	41,050	40,936	40,822	40,707	40,593	494,654
	b Debt Component (Line 6 x Debt Component x 1/12)		11,888	11,855	11,823	11,790	11,758	11,726	11,693	11,661	11,628	11,596	11,563	11,531	140,512
8	Investment Expenses														
	a Depreciation (E)		15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,542	15,542	186,504
	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)		69,279	69,132	68,986	68,839	68,692	68,546	68,399	68,253	68,106	67,960	67,812	67,666	821,670
	a Recoverable Costs Allocated to Energy		5,329	5,318	5,307	5,295	5,284	5,273	5,261	5,250	5,239	5,228	5,216	5,205	63,205
	b Recoverable Costs Allocated to Demand		63,950	63,814	63,679	63,544	63,408	63,273	63,138	63,003	62,867	62,732	62,596	62,461	758,465
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		5,143	5,128	5,128	5,119	5,113	5,101	5,090	5,080	5,062	5,043	5,025	5,017	61,049
13	Retail Demand-Related Recoverable Costs (I)		61,807	61,675	61,545	61,414	61,283	61,153	61,022	60,892	60,760	60,630	60,498	60,368	733,047
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		66,950	66,803	66,673	66,533	66,396	66,254	66,112	65,972	65,822	65,673	65,523	65,385	794,096

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) 3.2% 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 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR/CAVR Compliance
P.E.s 1034, 1035, 1036, 1037, 1222, 1362, 1468, 1469, 1512, 1513, 1646, 1647, 1684, 1824, & 1826
(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		66,622	42,172	74,636	24,425	666,252	27,146,843	219,847	68,034	327,789	380,840	2,248,016	208,633	
	b Clearings to Plant		38,759	(286)	0	0	672,015	27,059,453	110,000	0	0	149,608	2,000,000	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	38,759	38,473	38,473	38,473	710,488	27,769,941	27,879,941	27,879,941	27,879,941	28,029,549	30,029,549	30,029,549	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	(758)	(38,355)	(112,179)	(186,149)	(260,119)	(334,114)	(410,801)	(490,155)	
4	CWIP - Non Interest Bearing	0	27,863	70,321	144,957	169,382	163,619	251,009	360,856	428,890	756,679	987,911	1,235,927	1,444,560	
5	Net Investment (Lines 2 + 3 + 4)	0	66,622	108,794	183,430	207,855	873,349	27,982,595	28,128,618	28,122,682	28,376,501	28,683,346	30,854,675	30,983,954	
6	Average Net Investment		33,311	87,708	146,112	195,643	540,602	14,427,972	28,055,607	28,125,650	28,249,592	28,529,924	29,769,011	30,919,315	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		245	644	1,073	1,437	3,972	106,002	206,125	206,639	207,550	209,609	218,713	227,164	1,389,173
	b Debt Component (Line 6 x Debt Component x 1/12)		70	183	305	408	1,128	30,111	58,552	58,698	58,957	59,542	62,128	64,529	394,611
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	758	37,597	73,824	73,970	73,970	73,995	76,687	79,354	490,155
	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)		315	827	1,378	1,845	5,858	173,710	338,501	339,307	340,477	343,146	357,528	371,047	2,273,939
	a Recoverable Costs Allocated to Energy		315	827	1,378	1,845	5,858	173,710	338,501	339,307	340,477	343,146	357,528	371,047	2,273,939
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		304	797	1,331	1,784	5,669	168,049	327,526	328,335	328,961	331,025	344,430	357,634	2,195,845
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)		304	797	1,331	1,784	5,669	168,049	327,526	328,335	328,961	331,025	344,430	357,634	2,195,845

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $0; Smith $0; Daniel $0, Scholz $0. Ending Balances: Crist $27,769,941; Smith $149,608, Daniel $0, Scholz $0.
(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: 3.2%, Plant Smith Steam 2.5%, Smith CT 0.4%, Daniel 3.1%, Scholz 4.2%. Portion of PE 1222 is transmission 0.1833%, 0.1917%, 0.3417%, 0.2167%.
(F) Portion of PE 1222 applicable 7 year amortization period beginning in 2008.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) Project #1222 qualifies for AFUDC treatment. As portions of the project are moved to P-I-S, they are included in the ECRC.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2007 - December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.1280
(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	23,633	7	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	23,633	7	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	23,633	23,640	23,640	23,640	23,640	23,640	23,640	23,640	
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	23,633	23,640	23,640	23,640	23,640	23,640	23,640	23,640	
6	Average Net Investment		0	0	0	0	11,817	23,637	23,640	23,640	23,640	23,640	23,640	23,640	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	87	174	174	174	174	174	174	174	1,305
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	25	49	49	49	49	49	49	49	368
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	112	223	223	223	223	223	223	223	1,673
	a Recoverable Costs Allocated to Energy		0	0	0	0	112	223	223	223	223	223	223	223	1,673
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	108	216	216	216	215	215	215	215	1,616
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	108	216	216	216	215	215	215	215	1,616

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), 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) 5 year amortization beginning 2008.
(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 2007 - December 2007

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		14,250,000	0	0	29,755	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	518,044	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	10,583,118	24,381,657	23,458,100	22,443,092	21,754,017	20,818,122	19,805,303	18,648,011	17,480,417	16,419,280	15,432,045	14,558,685	13,556,340	
	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	(931,498)	(926,430)	(921,363)	(916,296)	(911,229)	(1,379,054)	(1,328,835)	(1,278,616)	(1,228,397)	(1,178,178)	(1,127,959)	(1,077,740)	(1,027,521)	
3	Total Working Capital Balance	9,651,620	23,455,227	22,536,737	21,526,796	20,842,788	19,439,068	18,476,468	17,369,395	16,252,020	15,241,102	14,304,086	13,480,945	12,528,819	
4	Average Net Working Capital Balance		16,553,424	22,995,982	22,031,767	21,184,792	20,140,928	18,957,768	17,922,932	16,810,708	15,746,561	14,772,594	13,892,516	13,004,882	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		121,618	168,951	161,867	155,645	147,975	139,283	131,680	123,508	115,690	108,534	102,068	95,547	1,572,366
	b Debt Component (Line 4 x Debt Component x 1/12)		34,547	47,993	45,980	44,213	42,034	39,565	37,405	35,084	32,863	30,830	28,994	27,141	446,649
6	Total Return Component (D)		156,165	216,944	207,847	199,858	190,009	178,848	169,085	158,592	148,553	139,364	131,062	122,688	2,019,015
7	Expenses														
	a Gains		(5,068)	(5,067)	(5,067)	(5,067)	(50,219)	(50,219)	(50,219)	(50,219)	(50,219)	(50,219)	(50,219)	(50,219)	(422,021)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		451,461	923,557	1,015,008	718,830	935,895	1,012,819	1,157,292	1,167,594	1,061,137	987,235	873,360	1,002,345	11,306,533
8	Net Expenses (E)		446,393	918,490	1,009,941	713,763	885,676	962,600	1,107,073	1,117,375	1,010,918	937,016	823,141	952,126	10,884,512
9	Total System Recoverable Expenses (Lines 6 + 8)		602,558	1,135,434	1,217,788	913,621	1,075,685	1,141,448	1,276,158	1,275,967	1,159,471	1,076,380	954,203	1,074,814	12,903,527
	a Recoverable Costs Allocated to Energy		602,558	1,135,434	1,217,788	913,621	1,075,685	1,141,448	1,276,158	1,275,967	1,159,471	1,076,380	954,203	1,074,814	12,903,527
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9645125	0.9635375	0.9655469	0.9660024	0.9670112	0.9667368	0.9669007	0.9669871	0.9655013	0.9640012	0.9626918	0.9631757	
11	Demand Jurisdictional Factor		0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	
12	Retail Energy-Related Recoverable Costs (B)		581,582	1,094,799	1,176,655	883,178	1,040,928	1,104,252	1,234,782	1,234,707	1,120,254	1,038,358	919,246	1,035,959	12,464,700
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)		581,582	1,094,799	1,176,655	883,178	1,040,928	1,104,252	1,234,782	1,234,707	1,120,254	1,038,358	919,246	1,035,959	12,464,700

Notes:
(A) Equity Component has been grossed up for taxes. Based on ROE of 12% and weighted income tax rate of 38.575%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Schedule 1P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered

For the Projected Period
January 2008 - December 2008

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)	11,428,287	2,231,313	13,659,600
	b Projected Capital Projects (Schedule 3P, Lines 7, 8 & 9)	32,972,623	3,228,971	36,201,594
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	44,400,910	5,460,284	49,861,194
2	True-Up for Estimated Over/(Under) Recovery for the period January 2007 - December 2007 (Schedule 1E, Line 3)	(1,876,694)	(241,232)	(2,117,926)
3	Final True-Up for the period January 2006 - December 2006 (Schedule 1A, Line 3)	1,965,472	292,913	2,258,385
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2008 - December 2008 (Line 1c - Line 2 - Line 3)	44,312,132	5,408,603	49,720,735
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	44,344,037	5,412,497	49,756,534

Notes:
Allocation to energy and demand in each period are in proportion to the respective period split of costs indicated on Lines 7 & 8 of Schedules 5E & 7E and 5A & 7A.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI **EXHIBIT** 42
COMPANY Gulf Power Company
WITNESS R. J. Martin (RJM-3)
DATE 11-06-07

001

Gulf Power Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2008 - December 2008

Schedule 2P

O & M Activities
(in Dollars)

Line		January	February	March	April	May	June	July	August	September	October	November	December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of O & M Activities															
	.1 Sulfur	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.2 Air Emission Fees	0	650,000	5,500	0	0	0	0	0	124,374	0	0	0	779,874	0	779,874
	.3 Title V	5,838	8,238	8,533	6,411	6,411	9,961	6,405	8,879	8,977	6,410	5,983	9,525	91,571	0	91,571
	.4 Asbestos Fees	1,250	0	500	0	0	0	0	0	0	0	0	500	2,250	2,250	0
	.5 Emission Monitoring	45,576	48,953	70,772	46,144	46,144	70,894	46,159	49,443	73,544	46,551	51,551	67,323	663,054	0	663,054
	.6 General Water Quality	25,654	26,085	29,429	25,679	28,343	35,193	29,942	27,371	29,429	25,679	25,679	30,430	338,913	338,913	0
	.7 Groundwater Contamination Investigation	114,160	123,598	115,065	114,755	114,756	115,103	114,779	124,507	115,107	114,756	114,756	115,134	1,396,476	1,396,476	0
	.8 State NPDES Administration	34,500	0	0	0	0	0	0	0	0	0	7,500	0	42,000	42,000	0
	.9 Lead and Copper Rule	4,000	0	4,500	0	0	4,000	0	0	4,000	0	5,000	0	21,500	21,500	0
	.10 Env Auditing/Assessment	0	0	0	0	0	0	0	0	650	0	0	650	1,300	1,300	0
	.11 General Solid & Hazardous Waste	26,560	31,214	26,864	26,848	26,848	26,874	26,848	31,650	26,874	26,848	26,848	26,909	331,185	331,185	0
	.12 Above Ground Storage Tanks	2,981	2,904	75,417	16,014	2,974	2,901	2,881	2,857	2,910	2,870	62,854	2,937	180,500	180,500	0
	.13 Low Nox	0	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	0
	.15 Mercury Emissions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.16 Sodium Injection	19,600	18,900	19,600	19,600	20,300	20,300	20,300	19,600	19,600	19,600	19,600	21,000	238,000	0	238,000
	.17 Gulf Coast Ozone Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.18 SPCC Substation Project	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.19 FDEP NOX Reduction Agreement	242,855	226,668	248,752	243,112	270,579	311,222	270,579	254,392	237,472	237,472	243,112	275,490	3,061,705	0	3,061,705
	.20 CAIR/CAMR/CAVR Compliance Program	12,197	12,197	12,197	12,197	12,197	12,196	66,836	66,836	16,836	16,836	16,836	18,040	275,401	0	275,401
	.21 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.22 Annual NOx Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.23 Seasonal NOx Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 SO_2 Allowances	588,857	550,535	633,266	605,412	589,295	650,128	655,559	639,792	562,798	535,556	358,224	355,728	6,725,150	0	6,725,150
2	Total of O & M Activities	1,124,028	1,699,292	1,250,395	1,116,172	1,117,847	1,258,772	1,240,288	1,225,327	1,222,571	1,032,578	937,943	923,666	14,148,879	2,314,124	11,834,755
3	Recoverable Costs Allocated to Energy	914,923	1,515,491	998,620	932,876	944,926	1,074,701	1,065,838	1,038,942	1,043,601	862,425	695,306	747,106	11,834,755		
4	Recoverable Costs Allocated to Demand	209,105	183,801	251,775	183,296	172,921	184,071	174,450	186,385	178,970	170,153	242,637	176,560	2,314,124		
5	Retail Energy Jurisdictional Factor	0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155			
6	Retail Demand Jurisdictional Factor	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160			
7	Jurisdictional Energy Recoverable Costs (A)	882,235	1,461,039	962,583	900,686	914,445	1,040,831	1,031,211	1,005,474	1,008,354	831,971	669,480	719,978	11,428,287		
8	Jurisdictional Demand Recoverable Costs (B)	201,622	177,224	242,765	176,737	166,733	177,484	168,207	179,715	172,566	164,064	233,954	170,242	2,231,313		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	1,083,857	1,638,263	1,205,348	1,077,423	1,081,178	1,218,315	1,199,418	1,185,189	1,180,920	996,035	903,434	890,220	13,659,600		

Notes:
(A) Line 3 x Line 5 x 1.0007 line loss multiplier
(B) Line 4 x Line 6

Schedule 3P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 - December 2008

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	Energy
1	Description of Investment Projects (A)															
	.1 Air Quality Assurance Testing	3,998	3,974	3,948	3,924	3,899	3,875	3,849	3,825	3,800	3,776	3,750	3,726	46,344	0	46,344
	.2 Crist 5, 6 & 7 Precipitator Projects	164,511	164,039	163,566	163,092	162,620	162,147	161,673	161,201	160,728	161,434	163,984	165,347	1,954,342	0	1,954,342
	.3 Crist 7 Flue Gas Conditioning	14,068	14,067	14,064	14,063	14,060	14,059	14,057	14,055	14,053	14,051	14,049	14,047	168,693	0	168,693
	.4 Low NOx Burners, Crist 6 & 7	172,283	172,054	171,825	171,596	171,367	171,138	170,909	170,680	170,452	170,222	169,993	169,765	2,052,284	0	2,052,284
	.5 CEMs- Plants Crist, Scholz, Smith, and Daniel	65,900	66,780	68,561	71,048	74,513	76,400	76,117	75,991	75,864	75,738	75,611	75,484	878,007	0	878,007
	.6 Sub. Contam. Mobile Groundwater Treat. Sys.	8,797	8,779	8,762	8,744	8,727	8,710	8,693	8,675	8,658	8,640	8,623	8,606	104,414	96,382	8,032
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	2,349	2,344	2,338	2,333	2,327	2,321	2,316	2,311	2,304	2,299	2,293	2,288	27,823	25,683	2,140
	.8 Crist Cooling Tower Cell	5,206	5,205	5,203	5,202	5,199	5,198	5,197	5,195	5,194	5,192	5,190	5,189	62,370	57,573	4,797
	.9 Crist 1-5 Dechlorination	2,406	2,399	2,391	2,383	2,376	2,368	2,361	2,353	2,346	2,338	2,330	2,323	28,374	26,191	2,183
	.10 Crist Diesel Fuel Oil Remediation	603	601	600	598	596	595	592	591	589	587	586	583	7,121	6,574	547
	.11 Crist Bulk Tanker Unload Sec Contain Struc	801	799	796	794	791	788	786	783	781	778	776	773	9,446	8,720	726
	.12 Crist IWW Sampling System	467	466	463	462	461	459	458	457	454	453	452	450	5,502	5,078	424
	.13 Sodium Injection System	4,212	4,202	4,193	4,183	4,174	4,165	4,155	4,146	4,137	4,128	4,119	4,109	49,923	0	49,923
	.14 Smith Stormwater Collection System	21,892	21,838	21,783	21,729	21,673	21,618	21,564	21,509	21,455	21,400	21,346	21,291	259,098	239,167	19,931
	.15 Smith Waste Water Treatment Facility	3,045	3,041	3,039	3,035	3,031	3,027	3,024	3,021	3,017	3,013	3,010	3,007	36,310	33,517	2,793
	.16 Daniel Ash Management Project	179,300	178,861	178,422	177,982	177,543	175,861	174,165	173,697	173,229	172,760	172,292	171,823	2,105,935	1,943,939	161,993
	.17 Smith Water Conservation	1,401	1,398	1,396	1,392	1,390	1,387	1,384	1,382	1,379	1,377	1,374	1,371	16,631	15,352	1,279
	.18 Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.19 Crist FDEP Agreement for Ozone Attainment	1,529,687	1,526,028	1,522,603	1,522,944	1,523,047	1,519,384	1,515,722	1,512,058	1,513,490	1,515,511	1,515,748	1,515,370	18,231,592	0	18,231,592
	.20 Crist Stormwater Collection System	10,830	10,807	10,784	10,761	10,738	10,715	10,692	10,668	10,645	10,622	10,599	10,576	128,437	118,557	9,880
	.21 Crist Common FTIR Monitor	686	684	683	682	679	678	676	675	673	671	670	669	8,126	0	8,126
	.22 Precipitator Upgrades for CAM Compliance	226,297	255,130	292,923	326,482	337,856	337,202	336,548	335,894	335,240	334,587	333,933	333,279	3,785,371	0	3,785,371
	.23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 Crist Water Conservation	1,104	1,101	1,099	1,096	1,094	1,091	1,090	1,087	1,085	1,082	1,080	1,077	13,086	12,079	1,007
	.25 Plant NPDES Permit Compliance Projects	67,520	67,550	67,757	67,964	68,370	68,598	68,447	68,297	68,147	67,996	67,846	67,695	816,187	753,404	62,783
	.26 CAIR/CAMR/CAVR Compliance Program	379,421	390,898	398,809	426,900	456,295	466,640	476,047	487,860	511,497	535,347	550,634	600,381	5,680,729	0	5,680,729
	.27 General Water Quality	615	611	607	604	601	597	593	589	585	582	578	574	7,136	6,588	548
	.28 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.29 Annual Nox Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.30 Seasonal Nox Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.31 SO2 Allowances	115,419	110,045	104,461	98,618	92,983	87,136	80,977	74,867	69,194	64,013	59,797	56,429	1,013,939	0	1,013,939
2	Total Investment Projects - Recoverable Costs	2,982,818	3,013,701	3,051,076	3,108,611	3,146,410	3,146,157	3,142,092	3,141,867	3,158,996	3,178,597	3,190,663	3,236,232	37,497,220	3,348,804	34,148,413
3	Recoverable Costs Allocated to Energy	2,700,046	2,731,424	2,769,132	2,826,998	2,864,947	2,866,159	2,863,912	2,864,376	2,882,194	2,902,487	2,915,239	2,961,499	34,148,413		
4	Recoverable Costs Allocated to Demand	282,773	282,278	281,942	281,612	281,462	279,998	278,181	277,491	276,801	276,110	275,424	274,732	3,348,804		
5	Retail Energy Jurisdictional Factor	0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155			
6	Retail Demand Jurisdictional Factor	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160			
7	Jurisdictional Energy Recoverable Costs (B)	2,603,581	2,633,283	2,669,203	2,729,448	2,772,531	2,775,831	2,770,870	2,772,106	2,784,850	2,799,995	2,806,959	2,853,966	32,972,623		
8	Jurisdictional Demand Recoverable Costs (C)	272,654	272,177	271,853	271,535	271,390	269,979	268,227	267,561	266,896	266,230	265,568	264,901	3,228,971		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	2,876,235	2,905,460	2,941,056	3,000,983	3,043,921	3,045,810	3,039,097	3,039,667	3,051,746	3,066,225	3,072,527	3,118,867	36,201,594		

Notes:

(A) Each project's Total System Recoverable Expenses as shown on Schedule 4P, Line 9. Allowances recoverable costs shown on Schedule 4P, Line 6
(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 2008 - December 2008

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)	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	
3	Less: Accumulated Depreciation (C)	(73,214)	(75,837)	(78,460)	(81,083)	(83,706)	(86,329)	(88,952)	(91,575)	(94,198)	(96,821)	(99,444)	(102,067)	(104,690)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	147,080	144,457	141,834	139,211	136,588	133,965	131,342	128,719	126,096	123,473	120,850	118,227	115,604	
6	Average Net Investment		145,769	143,146	140,523	137,900	135,277	132,654	130,031	127,408	124,785	122,162	119,539	116,916	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,071	1,052	1,032	1,013	994	975	955	936	917	898	878	859	11,580
	b Debt Component (Line 6 x Debt Component x 1/12)		304	299	293	288	282	277	271	266	260	255	249	244	3,288
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	31,476
	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)		3,998	3,974	3,948	3,924	3,899	3,875	3,849	3,825	3,800	3,776	3,750	3,726	46,344
	a Recoverable Costs Allocated to Energy		3,998	3,974	3,948	3,924	3,899	3,875	3,849	3,825	3,800	3,776	3,750	3,726	46,344
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		3,855	3,831	3,806	3,789	3,773	3,753	3,724	3,702	3,672	3,643	3,611	3,591	44,750
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)		3,855	3,831	3,806	3,789	3,773	3,753	3,724	3,702	3,672	3,643	3,611	3,591	44,750

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) PE 1244 7 year amorization; PE 1006 fully amortized
(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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1038, 1119, 1216, 1243, 1249
(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	250,000	250,000	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	500,000	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)	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	14,531,878	15,031,878	15,031,878	
3	Less: Accumulated Depreciation (C)	(2,382,646)	(2,432,778)	(2,482,910)	(2,533,042)	(2,583,174)	(2,633,306)	(2,683,438)	(2,733,570)	(2,783,702)	(2,833,834)	(2,883,966)	(2,934,765)	(2,986,231)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	250,000	0	0	
5	Net Investment (Lines 2 + 3 + 4)	12,149,232	12,099,100	12,048,968	11,998,836	11,948,704	11,898,572	11,848,440	11,798,308	11,748,176	11,698,044	11,897,912	12,097,113	12,045,647	
6	Average Net Investment		12,124,166	12,074,034	12,023,902	11,973,770	11,923,638	11,873,506	11,823,374	11,773,242	11,723,110	11,797,978	11,997,513	12,071,380	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		89,076	88,708	88,340	87,971	87,603	87,235	86,866	86,498	86,130	86,680	88,146	88,688	1,051,941
	b Debt Component (Line 6 x Debt Component x 1/12)		25,303	25,199	25,094	24,989	24,885	24,780	24,675	24,571	24,466	24,622	25,039	25,193	298,816
8	Investment Expenses														
	a Depreciation (E)		38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	38,757	39,424	40,091	467,085
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	11,375	136,500
	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)		164,511	164,039	163,566	163,092	162,620	162,147	161,673	161,201	160,728	161,434	163,984	165,347	1,954,342
	a Recoverable Costs Allocated to Energy		164,511	164,039	163,566	163,092	162,620	162,147	161,673	161,201	160,728	161,434	163,984	165,347	1,954,342
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		158,633	158,145	157,663	157,464	157,374	157,037	156,421	156,008	155,300	155,733	157,893	159,343	1,887,014
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)		158,633	158,145	157,663	157,464	157,374	157,037	156,421	156,008	155,300	155,733	157,893	159,343	1,887,014

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) 3.2% 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 Projected Period Amount
January 2008 - December 2008

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)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,469,711	1,469,507	1,469,303	1,469,099	1,468,895	1,468,691	1,468,487	1,468,283	1,468,079	1,467,875	1,467,671	1,467,467	1,467,263	
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)	1,469,711	1,469,507	1,469,303	1,469,099	1,468,895	1,468,691	1,468,487	1,468,283	1,468,079	1,467,875	1,467,671	1,467,467	1,467,263	
6	Average Net Investment		1,469,609	1,469,405	1,469,201	1,468,997	1,468,793	1,468,589	1,468,385	1,468,181	1,467,977	1,467,773	1,467,569	1,467,365	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,797	10,796	10,794	10,793	10,791	10,790	10,788	10,787	10,785	10,784	10,782	10,781	129,468
	b Debt Component (Line 6 x Debt Component x 1/12)		3,067	3,067	3,066	3,066	3,065	3,065	3,065	3,064	3,064	3,063	3,063	3,062	36,777
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		204	204	204	204	204	204	204	204	204	204	204	204	2,448
	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)		14,068	14,067	14,064	14,063	14,060	14,059	14,057	14,055	14,053	14,051	14,049	14,047	168,693
	a Recoverable Costs Allocated to Energy		14,068	14,067	14,064	14,063	14,060	14,059	14,057	14,055	14,053	14,051	14,049	14,047	168,693
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		13,565	13,562	13,556	13,578	13,606	13,616	13,600	13,602	13,578	13,555	13,527	13,537	162,882
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)		13,565	13,562	13,556	13,578	13,606	13,616	13,600	13,602	13,578	13,555	13,527	13,537	162,882

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) 3.2% 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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242 & 1284
(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)	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	9,097,923	
3	Less: Accumulated Depreciation (C)	6,604,119	6,579,855	6,555,591	6,531,327	6,507,063	6,482,799	6,458,535	6,434,271	6,410,007	6,385,743	6,361,479	6,337,215	6,312,951	
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)	15,702,042	15,677,778	15,653,514	15,629,250	15,604,986	15,580,722	15,556,458	15,532,194	15,507,930	15,483,666	15,459,402	15,435,138	15,410,874	
6	Average Net Investment		15,689,910	15,665,646	15,641,382	15,617,118	15,592,854	15,568,590	15,544,326	15,520,062	15,495,798	15,471,534	15,447,270	15,423,006	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		115,274	115,096	114,917	114,739	114,561	114,382	114,204	114,026	113,848	113,669	113,491	113,313	1,371,520
	b Debt Component (Line 6 x Debt Component x 1/12)		32,745	32,694	32,644	32,593	32,542	32,492	32,441	32,390	32,340	32,289	32,238	32,188	389,596
8	Investment Expenses														
	a Depreciation (E)		24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	24,264	291,168
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		172,283	172,054	171,825	171,596	171,367	171,138	170,909	170,680	170,452	170,222	169,993	169,765	2,052,284
	a Recoverable Costs Allocated to Energy		172,283	172,054	171,825	171,596	171,367	171,138	170,909	170,680	170,452	170,222	169,993	169,765	2,052,284
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		166,128	165,872	165,624	165,675	165,839	165,745	165,357	165,182	164,695	164,211	163,679	163,601	1,981,608
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)		166,128	165,872	165,624	165,675	165,839	165,745	165,357	165,182	164,695	164,211	163,679	163,601	1,981,608

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) 3.2% 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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CEMs- Plants Crist, Scholz, Smith, and Daniel
P.E.s 1154, 1164, 1217, 1240, 1245, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1364, 1440, 1441, 1442, 1444, 1445, 1454, 1459, 1460, 1558, 1570, 1658, 1829 & 1830
(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		60,000	150,000	200,000	300,000	300,000	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	310,000	0	969,999	0	0	0	0	0	0	0	
	c Retirements		0	0	174,325	0	246,987	148,118	0	0	0	0	0	0	
	d Cost of Removal		0	0	1,000	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)	4,291,064	4,291,064	4,291,064	4,426,739	4,426,739	5,149,751	5,001,633	5,001,633	5,001,633	5,001,633	5,001,633	5,001,633	5,001,633	
3	Less: Accumulated Depreciation (C)	1,004,284	992,532	980,780	1,144,115	1,131,888	1,365,894	1,500,434	1,487,011	1,473,588	1,460,165	1,446,742	1,433,319	1,419,896	
4	CWIP - Non Interest Bearing	269,999	329,999	479,999	369,999	669,999	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	5,565,347	5,613,595	5,751,843	5,940,853	6,228,626	6,515,645	6,502,067	6,488,644	6,475,221	6,461,798	6,448,375	6,434,952	6,421,529	
6	Average Net Investment		5,589,471	5,682,719	5,846,348	6,084,740	6,372,136	6,508,856	6,495,356	6,481,933	6,468,510	6,455,087	6,441,664	6,428,241	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		41,066	41,751	42,953	44,705	46,816	47,821	47,721	47,623	47,524	47,426	47,327	47,228	549,961
	b Debt Component (Line 6 x Debt Component x 1/12)		11,665	11,860	12,201	12,699	13,299	13,584	13,556	13,528	13,500	13,472	13,444	13,416	156,224
8	Investment Expenses														
	a Depreciation (E)		11,620	11,620	11,858	12,095	12,849	13,446	13,291	13,291	13,291	13,291	13,291	13,291	153,234
	b Amortization (F)		132	132	132	132	132	132	132	132	132	132	132	132	1,584
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		1,417	1,417	1,417	1,417	1,417	1,417	1,417	1,417	1,417	1,417	1,417	1,417	17,004
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		65,900	66,780	68,561	71,048	74,513	76,400	76,117	75,991	75,864	75,738	75,611	75,484	878,007
	a Recoverable Costs Allocated to Energy		65,900	66,780	68,561	71,048	74,513	76,400	76,117	75,991	75,864	75,738	75,611	75,484	878,007
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		63,546	64,381	66,087	68,596	72,109	73,992	73,644	73,543	73,302	73,064	72,803	72,743	847,810
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)		63,546	64,381	66,087	68,596	72,109	73,992	73,644	73,543	73,302	73,064	72,803	72,743	847,810

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $2,232,602; Scholz $790,064; Smith $688,899; Daniel $579,498. Ending Balances: Crist, $2,232,602; Scholz $925,740; Smith $1,263,793; Daniel $579,498.
(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: 3.2%; Smith 2.5%; Scholz 4.2%; Daniel 3.1% annually
(F) PE 1364 & 1658 have a 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 Projected Period Amount
January 2008 - December 2008

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)	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	
3	Less: Accumulated Depreciation (C)	(179,301)	(181,137)	(182,973)	(184,809)	(186,645)	(188,481)	(190,317)	(192,153)	(193,989)	(195,825)	(197,661)	(199,497)	(201,333)	
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)	738,723	736,887	735,051	733,215	731,379	729,543	727,707	725,871	724,035	722,199	720,363	718,527	716,691	
6	Average Net Investment		737,805	735,969	734,133	732,297	730,461	728,625	726,789	724,953	723,117	721,281	719,445	717,609	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,421	5,407	5,394	5,380	5,367	5,353	5,340	5,326	5,313	5,299	5,286	5,272	64,158
	b Debt Component (Line 6 x Debt Component x 1/12)		1,540	1,536	1,532	1,528	1,524	1,521	1,517	1,513	1,509	1,505	1,501	1,498	18,224
8	Investment Expenses														
	a Depreciation (E)		1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836	22,032
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		8,797	8,779	8,762	8,744	8,727	8,710	8,693	8,675	8,658	8,640	8,623	8,606	104,414
	a Recoverable Costs Allocated to Energy		677	675	674	673	671	670	669	667	666	665	663	662	8,032
	b Recoverable Costs Allocated to Demand		8,120	8,104	8,088	8,071	8,056	8,040	8,024	8,008	7,992	7,975	7,960	7,944	96,382
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		653	651	650	650	649	649	647	646	644	642	638	638	7,757
13	Retail Demand-Related Recoverable Costs (I)		7,829	7,814	7,799	7,782	7,768	7,752	7,737	7,721	7,706	7,690	7,675	7,660	92,933
14	Total Juris. Recoverable Costs (Lines 12 + 13)		8,482	8,465	8,449	8,432	8,417	8,401	8,384	8,367	8,350	8,332	8,313	8,298	100,690

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 2.4% annually, PEs 3400 and 3412 depreciable at 2.4% annually
(F) The amortizable portion of PE 1007 is fully amortized
(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

600

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 - December 2008

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	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)	(56,572)	(57,166)	(57.760)	(58,354)	(58,948)	(59,542)	(60,136)	(60,730)	(61,324)	(61,918)	(62,512)	(63,106)	(63,700)	
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)	186,371	185,777	185,183	184,589	183,995	183,401	182,807	182,213	181,619	181,025	180,431	179,837	179,243	
6	Average Net Investment		186,074	185,480	184,886	184,292	183,698	183,104	182,510	181,916	181,322	180,728	180,134	179,540	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,367	1,363	1,358	1,354	1,350	1,345	1,341	1,337	1,332	1,328	1,323	1,319	16,117
	b Debt Component (Line 6 x Debt Component x 1/12)		388	387	386	385	383	382	381	380	378	377	376	375	4,578
8	Investment Expenses														
	a Depreciation (E)		594	594	594	594	594	594	594	594	594	594	594	594	7,128
	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)		2,349	2,344	2,338	2,333	2,327	2,321	2,316	2,311	2,304	2,299	2,293	2,288	27,823
	a Recoverable Costs Allocated to Energy		181	180	180	179	179	179	178	178	177	177	176	176	2,140
	b Recoverable Costs Allocated to Demand		2,168	2,164	2,158	2,154	2,148	2,142	2,138	2,133	2,127	2,122	2,117	2,112	25,683
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		175	174	174	173	173	173	172	172	171	171	169	170	2,067
13	Retail Demand-Related Recoverable Costs (I)		2,090	2,087	2,081	2,077	2,071	2,065	2,061	2,057	2,051	2,046	2,041	2,036	24,763
14	Total Juris. Recoverable Costs (Lines 12 + 13)		2,265	2,261	2,255	2,250	2,244	2,238	2,233	2,229	2,222	2,217	2,210	2,206	26,830

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,920 and Smith $93,023.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.2%; Smith 2.5% 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 Projected Period Amount
January 2008 - December 2008

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)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	534,743	534,581	534,419	534,257	534,095	533,933	533,771	533,609	533,447	533,285	533,123	532,961	532,799	
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)	534,743	534,581	534,419	534,257	534,095	533,933	533,771	533,609	533,447	533,285	533,123	532,961	532,799	
6	Average Net Investment		534,662	534,500	534,338	534,176	534,014	533,852	533,690	533,528	533,366	533,204	533,042	532,880	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,928	3,927	3,926	3,925	3,923	3,922	3,921	3,920	3,919	3,917	3,916	3,915	47,059
	b Debt Component (Line 6 x Debt Component x 1/12)		1,116	1,116	1,115	1,115	1,114	1,114	1,114	1,113	1,113	1,113	1,112	1,112	13,367
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		162	162	162	162	162	162	162	162	162	162	162	162	1,944
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		5,206	5,205	5,203	5,202	5,199	5,198	5,197	5,195	5,194	5,192	5,190	5,189	62,370
	a Recoverable Costs Allocated to Energy		400	400	400	400	400	400	400	400	400	399	399	399	4,797
	b Recoverable Costs Allocated to Demand		4,806	4,805	4,803	4,802	4,799	4,798	4,797	4,795	4,794	4,793	4,791	4,790	57,573
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		386	386	386	386	387	387	387	387	386	385	384	385	4,632
13	Retail Demand-Related Recoverable Costs (I)		4,634	4,633	4,631	4,630	4,627	4,626	4,625	4,623	4,622	4,621	4,620	4,619	55,511
14	Total Juris. Recoverable Costs (Lines 12 + 13)		5,020	5,019	5,017	5,016	5,014	5,013	5,012	5,010	5,008	5,006	5,004	5,004	60,143

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) 3.2% 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 Projected Period Amount
January 2008 - December 2008
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)	(136,085)	(136,899)	(137,713)	(138,527)	(139,341)	(140,155)	(140,969)	(141,783)	(142,597)	(143,411)	(144,225)	(145,039)	(145,853)	
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)	169,238	168,424	167,610	166,796	165,982	165,168	164,354	163,540	162,726	161,912	161,098	160,284	159,470	
6	Average Net Investment		168,831	168,017	167,203	166,389	165,575	164,761	163,947	163,133	162,319	161,505	160,691	159,877	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,240	1,234	1,228	1,222	1,216	1,210	1,205	1,199	1,193	1,187	1,181	1,175	14,490
	b Debt Component (Line 6 x Debt Component x 1/12)		352	351	349	347	346	344	342	340	339	337	335	334	4,116
8	Investment Expenses														
	a Depreciation (E)		814	814	814	814	814	814	814	814	814	814	814	814	9,768
	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)		2,406	2,399	2,391	2,383	2,376	2,368	2,361	2,353	2,346	2,338	2,330	2,323	28,374
	a Recoverable Costs Allocated to Energy		185	185	184	183	183	182	182	181	180	180	179	179	2,183
	b Recoverable Costs Allocated to Demand		2,221	2,214	2,207	2,200	2,193	2,186	2,179	2,172	2,166	2,158	2,151	2,144	26,191
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		178	178	177	177	177	176	176	175	174	174	172	173	2,107
13	Retail Demand-Related Recoverable Costs (I)		2,142	2,135	2,128	2,121	2,115	2,108	2,101	2,094	2,088	2,081	2,074	2,067	25,254
14	Total Juris. Recoverable Costs (Lines 12 + 13)		2,320	2,313	2,305	2,298	2,292	2,284	2,277	2,269	2,262	2,255	2,246	2,240	27,361

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) 3.2% 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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(24,421)	(24,605)	(24,789)	(24,973)	(25,157)	(25,341)	(25,525)	(25,709)	(25,893)	(26,077)	(26,261)	(26,445)	(26,629)	
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)	44,502	44,318	44,134	43,950	43,766	43,582	43,398	43,214	43,030	42,846	42,662	42,478	42,294	
6	Average Net Investment		44,410	44,226	44,042	43,858	43,674	43,490	43,306	43,122	42,938	42,754	42,570	42,386	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		326	325	324	322	321	320	318	317	315	314	313	311	3,826
	b Debt Component (Line 6 x Debt Component x 1/12)		93	92	92	92	91	91	90	90	90	89	89	88	1,087
8	Investment Expenses														
	a Depreciation (E)		184	184	184	184	184	184	184	184	184	184	184	184	2,208
	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)		603	601	600	598	596	595	592	591	589	587	586	583	7,121
	a Recoverable Costs Allocated to Energy		46	46	46	46	46	46	46	45	45	45	45	45	547
	b Recoverable Costs Allocated to Demand		557	555	554	552	550	549	546	546	544	542	541	538	6,574
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		44	44	44	44	45	45	45	44	43	43	43	43	527
13	Retail Demand-Related Recoverable Costs (I)		537	535	534	532	530	529	526	526	525	523	522	519	6,338
14	Total Juris. Recoverable Costs (Lines 12 + 13)		581	579	578	576	575	574	571	570	568	566	565	562	6,865

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) 3.2% 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 Projected Period Amount
January 2008 - December 2008

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)	(45,174)	(45,445)	(45,716)	(45,987)	(46,258)	(46,529)	(46,800)	(47,071)	(47,342)	(47,613)	(47,884)	(48,155)	(48,426)	
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)	56,321	56,050	55,779	55,508	55,237	54,966	54,695	54,424	54,153	53,882	53,611	53,340	53,069	
6	Average Net Investment		56,186	55,915	55,644	55,373	55,102	54,831	54,560	54,289	54,018	53,747	53,476	53,205	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D		413	411	409	407	405	403	401	399	397	395	393	391	4,824
	b Debt Component (Line 6 x Debt Component x 1/12)		117	117	116	116	115	114	114	113	113	112	112	111	1,370
8	Investment Expenses														
	a Depreciation (E)		271	271	271	271	271	271	271	271	271	271	271	271	3,252
	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)		801	799	796	794	791	788	786	783	781	778	776	773	9,446
	a Recoverable Costs Allocated to Energy		62	61	61	61	61	61	60	60	60	60	60	59	726
	b Recoverable Costs Allocated to Demand		739	738	735	733	730	727	726	723	721	718	716	714	8,720
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		60	59	59	59	59	59	58	58	58	58	58	57	702
13	Retail Demand-Related Recoverable Costs (I)		713	712	709	707	704	701	700	697	695	692	690	688	8,408
14	Total Juris. Recoverable Costs (Lines 12 + 13)		773	771	768	766	763	760	758	755	753	750	748	745	9,110

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) 3.2% 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 Projected Period Amount
January 2008 - December 2008

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)	(26,830)	(26,989)	(27,148)	(27,307)	(27,466)	(27,625)	(27,784)	(27,943)	(28,102)	(28,261)	(28,420)	(28,579)	(28,738)	
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)	32,713	32,554	32,395	32,236	32,077	31,918	31,759	31,600	31,441	31,282	31,123	30,964	30,805	
6	Average Net Investment		32,634	32,475	32,316	32,157	31,998	31,839	31,680	31,521	31,362	31,203	31,044	30,885	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		240	239	237	236	235	234	233	232	230	229	228	227	2,800
	b Debt Component (Line 6 x Debt Component x 1/12)		68	68	67	67	67	66	66	66	65	65	65	64	794
8	Investment Expenses														
	a Depreciation (E)		159	159	159	159	159	159	159	159	159	159	159	159	1,908
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		467	466	463	462	461	459	458	457	454	453	452	450	5,502
	a Recoverable Costs Allocated to Energy		36	36	36	36	35	35	35	35	35	35	35	35	424
	b Recoverable Costs Allocated to Demand		431	430	427	426	426	424	423	422	419	418	417	415	5,078
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		35	35	35	35	34	34	34	34	34	34	34	34	412
13	Retail Demand-Related Recoverable Costs (I)		416	415	412	411	411	409	408	407	404	403	402	400	4,898
14	Total Juris. Recoverable Costs (Lines 12 + 13)		451	450	447	446	445	443	442	441	438	437	436	434	5,310

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) 3.2% 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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214 & 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)	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	
3	Less: Accumulated Depreciation (C)	(48,217)	(49,198)	(50,179)	(51,160)	(52,141)	(53,122)	(54,103)	(55,084)	(56,065)	(57,046)	(58,027)	(59,008)	(59,989)	
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)	342,902	341,921	340,940	339,959	338,978	337,997	337,016	336,035	335,054	334,073	333,092	332,111	331,130	
6	Average Net Investment		342,412	341,431	340,450	339,469	338,488	337,507	336,526	335,545	334,564	333,583	332,602	331,621	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,516	2,508	2,501	2,494	2,487	2,480	2,472	2,465	2,458	2,451	2,444	2,436	29,712
	b Debt Component (Line 6 x Debt Component x 1/12)		715	713	711	708	706	704	702	700	698	696	694	692	8,439
8	Investment Expenses														
	a Depreciation (E)		981	981	981	981	981	981	981	981	981	981	981	981	11,772
	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)		4,212	4,202	4,193	4,183	4,174	4,165	4,155	4,146	4,137	4,128	4,119	4,109	49,923
	a Recoverable Costs Allocated to Energy		4,212	4,202	4,193	4,183	4,174	4,165	4,155	4,146	4,137	4,128	4,119	4,109	49,923
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		4,062	4,051	4,042	4,039	4,039	4,034	4,020	4,012	3,997	3,982	3,966	3,960	48,204
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)		4,062	4,051	4,042	4,039	4,039	4,034	4,020	4,012	3,997	3,982	3,966	3,960	48,204

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $284,622 and Smith $106,497.
(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 3.2% annually; Smith 2.5% 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 Projected Period Amount
January 2008 - December 2008

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)	(1,073,516)	(1,079,312)	(1,085,108)	(1,090,904)	(1,096,700)	(1,102,496)	(1,108,292)	(1,114,088)	(1,119,884)	(1,125,680)	(1,131,476)	(1,137,272)	(1,143,068)	
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)	1,709,084	1,703,288	1,697,492	1,691,696	1,685,900	1,680,104	1,674,308	1,668,512	1,662,716	1,656,920	1,651,124	1,645,328	1,639,532	
6	Average Net Investment		1,706,186	1,700,390	1,694,594	1,688,798	1,683,002	1,677,206	1,671,410	1,665,614	1,659,818	1,654,022	1,648,226	1,642,430	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		12,535	12,493	12,450	12,408	12,365	12,322	12,280	12,237	12,195	12,152	12,110	12,067	147,614
	b Debt Component (Line 6 x Debt Component x 1/12)		3,561	3,549	3,537	3,525	3,512	3,500	3,488	3,476	3,464	3,452	3,440	3,428	41,932
8	Investment Expenses														
	a Depreciation (E)		5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	5,796	69,552
	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)		21,892	21,838	21,783	21,729	21,673	21,618	21,564	21,509	21,455	21,400	21,346	21,291	259,098
	a Recoverable Costs Allocated to Energy		1,684	1,680	1,676	1,671	1,667	1,663	1,659	1,655	1,650	1,646	1,642	1,638	19,931
	b Recoverable Costs Allocated to Demand		20,208	20,158	20,107	20,058	20,006	19,955	19,905	19,854	19,805	19,754	19,704	19,653	239,167
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		1,624	1,620	1,616	1,613	1,613	1,611	1,605	1,602	1,594	1,588	1,581	1,579	19,246
13	Retail Demand-Related Recoverable Costs (I)		19,485	19,437	19,387	19,340	19,290	19,241	19,193	19,144	19,096	19,047	18,999	18,950	230,609
14	Total Juris. Recoverable Costs (Lines 12 + 13)		21,109	21,057	21,003	20,953	20,903	20,852	20,798	20,746	20,690	20,635	20,580	20,529	249,855

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) 2.5% 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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E. 1466 & 1643
(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)	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	
3	Less: Accumulated Depreciation (C)	104,474	104,101	103,728	103,355	102,982	102,609	102,236	101,863	101,490	101,117	100,744	100,371	99,998	
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)	283,436	283,063	282,690	282,317	281,944	281,571	281,198	280,825	280,452	280,079	279,706	279,333	278,960	
6	Average Net Investment		283,250	282,877	282,504	282,131	281,758	281,385	281,012	280,639	280,266	279,893	279,520	279,147	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,081	2,078	2,076	2,073	2,070	2,067	2,065	2,062	2,059	2,056	2,054	2,051	24,792
	b Debt Component (Line 6 x Debt Component x 1/12)		591	590	590	589	588	587	586	586	585	584	583	583	7,042
8	Investment Expenses														
	a Depreciation (E)		373	373	373	373	373	373	373	373	373	373	373	373	4,476
	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)		3,045	3,041	3,039	3,035	3,031	3,027	3,024	3,021	3,017	3,013	3,010	3,007	36,310
	a Recoverable Costs Allocated to Energy		234	234	234	233	233	233	233	232	232	232	232	231	2,793
	b Recoverable Costs Allocated to Demand		2,811	2,807	2,805	2,802	2,798	2,794	2,791	2,789	2,785	2,781	2,778	2,776	33,517
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		226	226	226	225	225	226	225	225	224	224	223	223	2,698
13	Retail Demand-Related Recoverable Costs (I)		2,710	2,707	2,705	2,702	2,698	2,694	2,691	2,689	2,685	2,681	2,679	2,677	32,318
14	Total Juris. Recoverable Costs (Lines 12 + 13)		2,936	2,933	2,931	2,927	2,923	2,920	2,916	2,914	2,909	2,905	2,902	2,900	35,016

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) Smith 2.5% 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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E. 1535, 1555, & 1819
(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		5,604	5,604	5,604	5,604	5,605	5,603	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	33,624	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	1,000,000	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)	16,203,321	16,203,321	16,203,321	16,203,321	16,203,321	16,203,321	15,236,945	15,236,945	15,236,945	15,236,945	15,236,945	15,236,945	15,236,945	
3	Less: Accumulated Depreciation (C)	(5,900,730)	(5,952.895)	(6,005,060)	(6,057,225)	(6,109,390)	(6,161,555)	(5,212,472)	(5,262,141)	(5,311,810)	(5,361,479)	(5,411,148)	(5,460,817)	(5,510,486)	
4	CWIP - Non Interest Bearing	0	5,604	11,208	16,812	22,416	28,021	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	10,302,591	10,256,030	10,209,469	10,162,908	10,116,347	10,069,787	10,024,473	9,974,804	9,925,135	9,875,466	9,825,797	9,776,128	9,726,459	
6	Average Net Investment		10,279.311	10.232,750	10,186,189	10,139,628	10,093,067	10,047,130	9,999,639	9,949,970	9,900,301	9,850,632	9,800,963	9,751,294	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		75,522	75,180	74,838	74,496	74,154	73,816	73,467	73,102	72,738	72,373	72,008	71,643	883,337
	b Debt Component (Line 6 x Debt Component x 1/12)		21,453	21,356	21,259	21,161	21,064	20,968	20,869	20,766	20,662	20,558	20,455	20,351	250,922
8	Investment Expenses														
	a Depreciation (E)		41,853	41,853	41,853	41,853	41,853	40,605	39,357	39,357	39,357	39,357	39,357	39,357	486,012
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	10,312	123,744
	d Property Taxes		30,160	30,160	30,160	30,160	30,160	30,160	30,160	30,160	30,160	30,160	30,160	30,160	361,920
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		179.300	178,861	178,422	177,982	177,543	175,861	174,165	173,697	173,229	172,760	172,292	171,823	2,105,935
	a Recoverable Costs Allocated to Energy		13,792	13,759	13,724	13,691	13,657	13,528	13,397	13,361	13,326	13,289	13,253	13,216	161,993
	b Recoverable Costs Allocated to Demand		165,509	165,103	164,696	164,290	163,885	162,333	160,769	160,336	159,902	159,471	159,039	158,606	1,943,939
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		13,299	13,265	13,229	13,219	13,216	13,102	12,962	12,931	12,876	12,820	12,761	12,736	156,416
13	Retail Demand-Related Recoverable Costs (I)		159,586	159,195	158,803	158,411	158,021	156,524	155,016	154,599	154,180	153,764	153,348	152,930	1,874,377
14	Total Juris. Recoverable Costs (Lines 12 + 13)		172.885	172,460	172,032	171,630	171,237	169,626	167,978	167,530	167,056	166,584	166,109	165,666	2,030,793

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) 3.1% 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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 1620 & 1638
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	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)	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	134,135	
3	Less: Accumulated Depreciation (C)	(15,218)	(15,498)	(15,778)	(16,058)	(16,338)	(16,618)	(16,898)	(17,178)	(17,458)	(17,738)	(18,018)	(18,298)	(18,578)	
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)	118,917	118,637	118,357	118,077	117,797	117,517	117,237	116,957	116,677	116,397	116,117	115,837	115,557	
6	Average Net Investment		118,777	118,497	118,217	117,937	117,657	117,377	117,097	116,817	116,537	116,257	115,977	115,697	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		873	871	869	866	864	862	860	858	856	854	852	850	10,335
	b Debt Component (Line 6 x Debt Component x 1/12)		248	247	247	246	246	245	244	244	243	243	242	241	2,936
8	Investment Expenses														
	a Depreciation (E)		280	280	280	280	280	280	280	280	280	280	280	280	3,360
	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)		1,401	1,398	1,396	1,392	1,390	1,387	1,384	1,382	1,379	1,377	1,374	1,371	16,631
	a Recoverable Costs Allocated to Energy		108	108	107	107	107	107	106	106	106	106	106	105	1,279
	b Recoverable Costs Allocated to Demand		1,293	1,290	1,289	1,285	1,283	1,280	1,278	1,276	1,273	1,271	1,268	1,266	15,352
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		104	104	103	103	104	104	103	103	102	102	102	101	1,235
13	Retail Demand-Related Recoverable Costs (I)		1,247	1,244	1,243	1,239	1,237	1,234	1,232	1,230	1,227	1,226	1,223	1,221	14,803
14	Total Juris. Recoverable Costs (Lines 12 + 13)		1,351	1,348	1,346	1,342	1,341	1,338	1,335	1,333	1,329	1,328	1,325	1,322	16,038

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) 2.5% 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

020

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 - December 2008

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)	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 (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
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
(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) PE 4397 fully amortized.
(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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E. 1031, 1199, 1250, and 1287
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	a Expenditures/Additions		0	0	50,000	770,000	0	0	0	0	1,080,000	125,000	125,000	0	
	b Clearings to Plant		0	0	0	100,000	0	0	0	0	0	0	2,050,000	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) (J)	134,056,437	134,056,437	134,056,437	134,056,437	134,156,437	134,156,437	134,156,437	134,156,437	134,156,437	134,156,437	134,156,437	136,206,437	136,206,437	
3	Less: Accumulated Depreciation (C)	(12,842,640)	(13,230,627)	(13,618,614)	(14,006,601)	(14,394,722)	(14,782,976)	(15,171,230)	(15,559,484)	(15,947,738)	(16,335,992)	(16,724,246)	(17,115,233)	(17,508,954)	
4	CWIP - Non Interest Bearing (J)	0	0	0	50,000	720,000	720,000	720,000	720,000	720,000	1,800,000	1,925,000	0	0	
5	Net Investment (Lines 2 + 3 + 4)	121,213,797	120,825,810	120,437,823	120,099,836	120,481,715	120,093,461	119,705,207	119,316,953	118,928,699	119,620,445	119,357,191	119,091,204	118,697,483	
6	Average Net Investment		121,019,804	120,631,817	120,268,830	120,290,776	120,287,588	119,899,334	119,511,080	119,122,826	119,274,572	119,488,818	119,224,198	118,894,344	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		889,132	886,282	883,615	883,776	883,753	880,900	878,048	875,195	876,310	877,884	875,940	873,517	10,564,352
	b Debt Component (Line 6 x Debt Component x 1/12)		252,568	251,759	251,001	251,047	251,040	250,230	249,420	248,609	248,926	249,373	248,821	248,132	3,000,926
8	Investment Expenses														
	a Depreciation (E)		357,015	357,015	357,015	357,149	357,282	357,282	357,282	357,282	357,282	357,282	360,015	362,749	4,294,650
	b Amortization (F)		2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	27,504
	c Dismantlement		28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	28,680	344,160
	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)		1,529,687	1,526,028	1,522,603	1,522,944	1,523,047	1,519,384	1,515,722	1,512,058	1,513,490	1,515,511	1,515,748	1,515,370	18,231,592
	a Recoverable Costs Allocated to Energy		1,529,687	1,526,028	1,522,603	1,522,944	1,523,047	1,519,384	1,515,722	1,512,058	1,513,490	1,515,511	1,515,748	1,515,370	18,231,592
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		1,475,035	1,471,197	1,467,657	1,470,392	1,473,917	1,471,500	1,466,480	1,463,350	1,462,373	1,461,995	1,459,449	1,460,346	17,603,691
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)		1,475,035	1,471,197	1,467,657	1,470,392	1,473,917	1,471,500	1,466,480	1,463,350	1,462,373	1,461,995	1,459,449	1,460,346	17,603,691

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: 3.2% annually
(F) Portions of 1287 have 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
(J) Beginning balance differs from the 2007 estimated/actual true-up as a result of a correction to the projected 2007 CWIP balance.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Storm Water Collection System
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	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)	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	919,837	
3	Less: Accumulated Depreciation (C)	(30,628)	(33,081)	(35,534)	(37,987)	(40,440)	(42,893)	(45,346)	(47,799)	(50,252)	(52,705)	(55,158)	(57,611)	(60,064)	
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)	889,209	886,756	884,303	881,850	879,397	876,944	874,491	872,038	869,585	867,132	864,679	862,226	859,773	
6	Average Net Investment		887,983	885,530	883,077	880,624	878,171	875,718	873,265	870,812	868,359	865,906	863,453	861,000	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,524	6,506	6,488	6,470	6,452	6,434	6,416	6,398	6,380	6,362	6,344	6,326	77,100
	b Debt Component (Line 6 x Debt Component x 1/12)		1,853	1,848	1,843	1,838	1,833	1,828	1,823	1,817	1,812	1,807	1,802	1,797	21,901
8	Investment Expenses														
	a Depreciation (E)		2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	29,436
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		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)		10,830	10,807	10,784	10,761	10,738	10,715	10,692	10,668	10,645	10,622	10,599	10,576	128,437
	a Recoverable Costs Allocated to Energy		833	831	830	828	826	824	822	821	819	817	815	814	9,880
	b Recoverable Costs Allocated to Demand		9,997	9,976	9,954	9,933	9,912	9,891	9,870	9,847	9,826	9,805	9,784	9,762	118,557
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		803	801	800	799	799	798	795	795	791	788	785	784	9,538
13	Retail Demand-Related Recoverable Costs (I)		9,639	9,619	9,598	9,578	9,557	9,537	9,517	9,495	9,474	9,454	9,434	9,413	114,315
14	Total Juris. Recoverable Costs (Lines 12 + 13)		10,442	10,420	10,398	10,377	10,356	10,335	10,312	10,290	10,265	10,242	10,219	10,197	123,853

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) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.2% 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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	
3	Less: Accumulated Depreciation (C)	(7,897)	(8,065)	(8,233)	(8,401)	(8,569)	(8,737)	(8,905)	(9,073)	(9,241)	(9,409)	(9,577)	(9,745)	(9,913)	
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)	54,973	54,805	54,637	54,469	54,301	54,133	53,965	53,797	53,629	53,461	53,293	53,125	52,957	
6	Average Net Investment		54,889	54,721	54,553	54,385	54,217	54,049	53,881	53,713	53,545	53,377	53,209	53,041	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		403	402	401	400	398	397	396	395	393	392	391	390	4,758
	b Debt Component (Line 6 x Debt Component x 1/12)		115	114	114	114	113	113	112	112	112	111	111	111	1,352
8	Investment Expenses														
	a Depreciation (E)		168	168	168	168	168	168	168	168	168	168	168	168	2,016
	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)		686	684	683	682	679	678	676	675	673	671	670	669	8,126
	a Recoverable Costs Allocated to Energy		686	684	683	682	679	678	676	675	673	671	670	669	8,126
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		661	659	658	658	657	657	654	653	650	647	645	645	7,844
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)		661	659	658	658	657	657	654	653	650	647	645	645	7,844

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) 3.2% 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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E. 1175, 1191, 1305, 1461, & 1462
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Amount
1	Investments (A)														
	a Expenditures/Additions		2,768,100	3,410,950	3,026,543	362,443	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	5,832,124	7,699,989	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) (J)	15.837,728	15,837,728	15,837,728	21,669,852	29,369,841	29,369,841	29,369,841	29,369,841	29,369,841	29,369,841	29,369,841	29,369,841	29,369,841	
3	Less: Accumulated Depreciation (C) (J)	(701,285)	(734,487)	(767,689)	(808,668)	(867,692)	(936,985)	(1,006,278)	(1,075,571)	(1,144,864)	(1,214,157)	(1,283,450)	(1,352,743)	(1,422,036)	
4	CWIP - Non Interest Bearing (J)	3,964,077	6,732,177	10,143,127	7,337,546	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (J)	19,100,520	21,835,418	25,213,166	28,198,730	28,502,149	28,432,856	28,363,563	28,294,270	28,224,977	28,155,684	28,086,391	28,017,098	27,947,805	
6	Average Net Investment		20,467,969	23,524,292	26,705,948	28,350,440	28,467,503	28,398,210	28,328,917	28,259,624	28,190,331	28,121,038	28,051,745	27,982,452	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		150,378	172,833	196,209	208,291	209,151	208,642	208,133	207,623	207,114	206,605	206,096	205,587	2,386,662
	b Debt Component (Line 6 x Debt Component x 1/12)		42,717	49,095	55,735	59,167	59,412	59,267	59,122	58,978	58,833	58,689	58,544	58,399	677,958
8	Investment Expenses														
	a Depreciation (E)		33,202	33,202	40,979	59,024	69,293	69,293	69,293	69,293	69,293	69,293	69,293	69,293	720,751
	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)		226,297	255,130	292,923	326,482	337,856	337,202	336,548	335,894	335,240	334,587	333,933	333,279	3,785,371
	a Recoverable Costs Allocated to Energy		226,297	255,130	292,923	326,482	337,856	337,202	336,548	335,894	335,240	334,587	333,933	333,279	3,785,371
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		218,212	245,963	282,352	315,216	326,958	326,575	325,614	325,074	323,917	322,772	321,530	321,178	3,655,361
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)		218,212	245,963	282,352	315,216	326,958	326,575	325,614	325,074	323,917	322,772	321,530	321,178	3,655,361

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $0; Smith $15,687,728; Scholz $150,000. Ending Balances: Crist, $13,532,113; Smith $15,687,728; Scholz $150,000.
(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 3.2%; Smith 2.5%; Scholz 4.2% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) Crist beginning balances differ from 2007 estimated/actual true-up due to planned outage being moved from fall 2007 to March 2008.

C-20

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E. 1218 & 1361
(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 (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component 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		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
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
(B) Beginning Balances: Crist $0: Scholz $0. Ending Balances: Crist, $0: Scholz $0.
(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 3.2% annually; Scholz 4.2% 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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Crist Water Conservation Project
P.E. 1227
(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)	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	93,735	
3	Less: Accumulated Depreciation (C)	(3,148)	(3,398)	(3,648)	(3,898)	(4,148)	(4,398)	(4,648)	(4,898)	(5,148)	(5,398)	(5,648)	(5,898)	(6,148)	
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)	90,587	90,337	90,087	89,837	89,587	89,337	89,087	88,837	88,587	88,337	88,087	87,837	87,587	
6	Average Net Investment		90,462	90,212	89,962	89,712	89,462	89,212	88,962	88,712	88,462	88,212	87,962	87,712	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		665	663	661	659	657	655	654	652	650	648	646	644	7,854
	b Debt Component (Line 6 x Debt Component x 1/12)		189	188	188	187	187	186	186	185	185	184	184	183	2,232
8	Investment Expenses														
	a Depreciation (E)		250	250	250	250	250	250	250	250	250	250	250	250	3,000
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,104	1,101	1,099	1,096	1,094	1,091	1,090	1,087	1,085	1,082	1,080	1,077	13,086
	a Recoverable Costs Allocated to Energy		85	85	85	84	84	84	84	84	83	83	83	83	1,007
	b Recoverable Costs Allocated to Demand		1,019	1,016	1,014	1,012	1,010	1,007	1,006	1,003	1,002	999	997	994	12,079
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		82	82	82	81	81	81	81	81	80	80	80	80	971
13	Retail Demand-Related Recoverable Costs (I)		983	980	978	976	974	971	970	967	966	963	961	958	11,647
14	Total Juris. Recoverable Costs (Lines 12 + 13)		1,065	1,062	1,060	1,057	1,055	1,052	1,051	1,048	1,046	1,043	1,041	1,038	12,618

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) 3.2% 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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Plant NPDES Permit Compliance Projects
P.E. 1204 & 1299
(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	37,500	37,500	37,500	37,500	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	150,000	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)	5,827,707	5,827,707	5,827,707	5,827,707	5,827,707	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	5,977,707	
3	Less: Accumulated Depreciation (C)	(310,341)	(325,883)	(341,425)	(356,967)	(372,509)	(388,251)	(404,193)	(420,135)	(436,077)	(452,019)	(467,961)	(483,903)	(499,845)	
4	CWIP - Non Interest Bearing	0	0	37,500	75,000	112,500	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	5,517,366	5,501,824	5,523,782	5,545,740	5,567,698	5,589,456	5,573,514	5,557,572	5,541,630	5,525,688	5,509,746	5,493,804	5,477,862	
6	Average Net Investment		5,509,595	5,512,803	5,534,761	5,556,719	5,578,577	5,581,485	5,565,543	5,549,601	5,533,659	5,517,717	5,501,775	5,485,833	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		40,479	40,503	40,664	40,825	40,986	41,007	40,890	40,773	40,656	40,539	40,422	40,304	488,048
	b Debt Component (Line 6 x Debt Component x 1/12)		11,499	11,505	11,551	11,597	11,642	11,649	11,615	11,582	11,549	11,515	11,482	11,449	138,635
8	Investment Expenses														
	a Depreciation (E)		15,542	15,542	15,542	15,542	15,742	15,942	15,942	15,942	15,942	15,942	15,942	15,942	189,504
	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)		67,520	67,550	67,757	67,964	68,370	68,598	68,447	68,297	68,147	67,996	67,846	67,695	816,187
	a Recoverable Costs Allocated to Energy		5,194	5,196	5,212	5,228	5,259	5,277	5,265	5,254	5,242	5,230	5,219	5,207	62,783
	b Recoverable Costs Allocated to Demand		62,326	62,354	62,545	62,736	63,111	63,321	63,182	63,043	62,905	62,766	62,627	62,488	753,404
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		5,008	5,009	5,024	5,048	5,089	5,111	5,094	5,085	5,065	5,045	5,025	5,018	60,621
13	Retail Demand-Related Recoverable Costs (I)		60,096	60,123	60,307	60,491	60,853	61,055	60,921	60,787	60,654	60,520	60,386	60,252	726,445
14	Total Juris. Recoverable Costs (Lines 12 + 13)		65,104	65,132	65,331	65,539	65,942	66,166	66,015	65,872	65,719	65,565	65,411	65,270	787,066

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) 3.2% 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 Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR/CAVR Compliance Program
P.E.s 1034, 1035, 1036, 1037, 1095, 1222, 1362, 1468, 1469, 1512, 1513, 1646, 1647, 1684, 1810, 1824, & 1826
(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		1,628,817	963,828	872,950	5,241,950	1,149,450	903,750	812,700	1,423,200	3,236,554	1,767,408	1,651,408	3,869,785	
	b Clearings to Plant (J)		0	0	0	0	0	1,362,891	500,000	796,887	836,439	0	0	20,913,075	
	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)	30,029,549	30,029,549	30,029,549	30,029,549	30,029,549	30,029,549	31,392,440	31,892,440	32,689,327	33,525,766	33,525,766	33,525,766	54,438,841	
3	Less: Accumulated Depreciation (C)	(490,155)	(569,967)	(649,779)	(729,591)	(809,403)	(889,215)	(970,446)	(1,053,764)	(1,139,144)	(1,226,998)	(1,315,932)	(1,404,866)	(1,518,459)	
4	CWIP - Non Interest Bearing	1,444,560	3,073,377	4,037,205	4,910,155	10,152,105	11,301,555	10,842,414	11,155,114	11,781,427	14,181,542	15,948,950	17,600,358	557,068	
5	Net Investment (Lines 2 + 3 + 4)	30,983,954	32,532,959	33,416,975	34,210,113	39,372,251	40,441,889	41,264,408	41,993,790	43,331,610	46,480,310	48,158,784	49,721,258	53,477,450	
6	Average Net Investment		31,758,457	32,974,967	33,813,544	36,791,182	39,907,070	40,853,149	41,629,099	42,662,700	44,905,960	47,319,547	48,940,021	51,599,354	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		233,329	242,267	248,428	270,305	293,197	300,148	305,849	313,443	329,924	347,657	359,562	379,100	3,623,209
	b Debt Component (Line 6 x Debt Component x 1/12)		66,280	68,819	70,569	76,783	83,286	85,261	86,880	89,037	93,719	98,756	102,138	107,688	1,029,216
8	Investment Expenses														
	a Depreciation (E)		79,354	79,354	79,354	79,354	79,354	80,773	82,860	84,922	87,396	88,476	88,476	113,135	1,022,808
	b Amortization (F)		458	458	458	458	458	458	458	458	458	458	458	458	5,496
	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)		379,421	390,898	398,809	426,900	456,295	466,640	476,047	487,860	511,497	535,347	550,634	600,381	5,680,729
	a Recoverable Costs Allocated to Energy		379,421	390,898	398,809	426,900	456,295	466,640	476,047	487,860	511,497	535,347	550,634	600,381	5,680,729
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		365,865	376,853	384,417	412,169	441,576	451,934	460,581	472,145	494,221	516,443	530,182	578,581	5,484,967
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)		365,865	376,853	384,417	412,169	441,576	451,934	460,581	472,145	494,221	516,443	530,182	578,581	5,484,967

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $29,879,941; Smith $149,608; Daniel $0, Scholz $0. Ending Balances: Crist $30,379,941; Smith $10,910,957, Daniel $12,351,056, Scholz $796,887.
(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: 3.2%, Plant Smith Steam 2.5%, Smith CT 0.4%, Daniel 3.1%, Scholz 4.2%. Portion of PE 1222 is transmission 2.2%, 2.3%, 4.1%, 2.6%.
(F) Portion of PE 1222 has a applicable 7 year amortization period beginning in 2008.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) Project #1222 qualifies for AFUDC treatment. As portions of the project are moved to P-I-S, they are included in the ECRC.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E. 1280
(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)	23,640	23,640	23,640	23,640	23,640	23,640	23,640	23,640	23,640	23,640	23,640	23,640	23,640	
3	Less: Accumulated Depreciation (C)	0	(394)	(788)	(1,182)	(1,576)	(1,970)	(2,364)	(2,758)	(3,152)	(3,546)	(3,940)	(4,334)	(4,728)	
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)	23,640	23,246	22,852	22,458	22,064	21,670	21,276	20,882	20,488	20,094	19,700	19,306	18,912	
6	Average Net Investment		23,443	23,049	22,655	22,261	21,867	21,473	21,079	20,685	20,291	19,897	19,503	19,109	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		172	169	166	164	161	158	155	152	149	146	143	140	1,875
	b Debt Component (Line 6 x Debt Component x 1/12)		49	48	47	46	46	45	44	43	42	42	41	40	533
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		394	394	394	394	394	394	394	394	394	394	394	394	4,728
	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)		615	611	607	604	601	597	593	589	585	582	578	574	7,136
	a Recoverable Costs Allocated to Energy		47	47	47	46	46	46	46	45	45	45	44	44	548
	b Recoverable Costs Allocated to Demand		568	564	560	558	555	551	547	544	540	537	534	530	6,588
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		45	45	45	44	45	45	45	44	43	43	42	42	528
13	Retail Demand-Related Recoverable Costs (I)		548	544	540	538	535	531	527	525	521	518	515	511	6,353
14	Total Juris. Recoverable Costs (Lines 12 + 13)		593	589	585	582	580	576	572	569	564	561	557	553	6,881

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). 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) 5 year amortization beginning 2008.
(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

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 - December 2008
Return on Capital Investments, Depreciation and Taxes
For Project: Mercury 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 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	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 (Line 4 x Equity Component x 1/12)(A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component 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
	c Mercury Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Net Expenses (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 6 + 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		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
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	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) 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)
Calculation of the Projected Period Amount
January 2008 - December 2008
Return on Capital Investments, Depreciation and Taxes
For Project: Annual NOx 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 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	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 (Line 4 x Equity Component x 1/12)(A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component 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
	c Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Net Expenses (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 6 + 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		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
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	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) 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)
Calculation of the Projected Period Amount
January 2008 - December 2008
Return on Capital Investments, Depreciation and Taxes
For Project: Seasonal NOx 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 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	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 (Line 4 x Equity Component x 1/12)(A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component 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
	c Seasonal NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Net Expenses (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 6 + 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		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
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	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) 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)
Calculation of the Projected Period Amount
January 2008 - December 2008
Return on Capital Investments, Depreciation and Taxes
For Project: SO_2 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 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	13,556,340	12,959,262	12,400,506	11,759,019	11,145,386	10,547,870	9,889,521	9,225,741	8,577,728	8,006,709	7,462,932	7,096,487	6,732,538	
	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	(1,027,521)	(1,019,300)	(1,011,079)	(1,002,858)	(994,637)	(986,416)	(978,195)	(969,974)	(961,753)	(953,532)	(945,311)	(937,090)	(928,869)	
3	Total Working Capital Balance	12,528,819	11,939,962	11,389,427	10,756,161	10,150,749	9,561,454	8,911,326	8,255,767	7,615,975	7,053,177	6,517,621	6,159,397	5,803,669	
4	Average Net Working Capital Balance		12,234,391	11,664,695	11,072,794	10,453,455	9,856,102	9,236,390	8,583,547	7,935,871	7,334,576	6,785,399	6,338,509	5,981,533	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12)(A)		89,886	85,701	81,352	76,802	72,413	67,860	63,063	58,305	53,887	49,852	46,569	43,946	789,636
	b Debt Component (Line 4 x Debt Component x 1/12)		25,533	24,344	23,109	21,816	20,570	19,276	17,914	16,562	15,307	14,161	13,228	12,483	224,303
6	Total Return Component (D)		115,419	110,045	104,461	98,618	92,983	87,136	80,977	74,867	69,194	64,013	59,797	56,429	1,013,939
7	Expenses:														
	a Gains		(8,221)	(8,221)	(8,221)	(8,221)	(8,221)	(8,221)	(8,221)	(8,221)	(8,221)	(8,221)	(8,221)	(8,221)	(98,652)
	b Losses														0
	c SO2 Allowance Expense		597,078	558,756	641,487	613,633	597,516	658,349	663,780	648,013	571,019	543,777	366,445	363,949	6,823,802
8	Net Expenses (E)		588,857	550,535	633,266	605,412	589,295	650,128	655,559	639,792	562,798	535,556	358,224	355,728	6,725,150
9	Total System Recoverable Expenses (Lines 6 + 8)		704,276	660,580	737,727	704,030	682,278	737,264	736,536	714,659	631,992	599,569	418,021	412,157	7,739,089
	a Recoverable Costs Allocated to Energy		704,276	660,580	737,727	704,030	682,278	737,264	736,536	714,659	631,992	599,569	418,021	412,157	7,739,089
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9635982	0.9633954	0.9632389	0.9648180	0.9670654	0.9678072	0.9668356	0.9671099	0.9655497	0.9640133	0.9621838	0.9630155	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)		679,114	636,845	711,105	679,736	660,269	714,029	712,608	691,638	610,647	578,397	402,495	397,191	7,474,074
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)		679,114	636,845	711,105	679,736	660,269	714,029	712,608	691,638	610,647	578,397	402,495	397,191	7,474,074

Notes:
(A) 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 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Air Quality Assurance Testing
PEs 1006 and 1244

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
This line item includes the audit test trailer and associated support equipment used to conduct Relative Accuracy Audits (RATAs) on the Continuous Emission Monitoring Systems (CEMs) as required by the 1990 Clean Air Act Amendments (CAAA).

Accomplishments:
The RATA test trailer CEM system was replaced during the 2002-2003 recovery period. The CEMs trailer was also replaced during 2005. These replacements provide Gulf with the accuracy and reliability needed to accurately measure SO_2, NOx, CO_2, and opacity and to further maintain compliance with CAAA requirements.

Project-to-Date: Plant-in-service of $220,294 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist 5, 6 & 7 Precipitator Projects
PEs 1038, 1119, 1216, 1243, and 1249

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Crist precipitator projects are necessary to improve particulate removal capabilities as a result of burning low sulfur coal. The larger more efficient precipitators with increased collection areas improve particulate collection efficiency.

Accomplishments:
The precipitators have successfully reduced particulate emissions while burning low sulfur coal. The upgraded Crist Unit 7 precipitator was placed in service during 2004 as part of the FDEP agreement.

Project-to-Date: Plant-in-service of $15,031,878 projected at December 2008.

Progress Summary: In-Service

Projections:
During the 2008 recovery period, Plant Crist plans to install a new purge air system on the Unit 6 precipitator to ensure that the insulators continue functioning properly in order to maintain compliance with the Clean Air Act Amendments. The 2008 projected expenditures for the purge air system are $500,000.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist 7 Flue Gas Conditioning
PE 1228

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
This project included the injection of sulfur trioxide into the flue gas to enhance particulate removal and improve the collection characteristics of fly ash. Retirement of the Plant Crist Unit 7 flue gas conditioning system was completed during July 2005.

Accomplishments:
The system enhanced particulate removal in the precipitator.

Project-to-Date: $0

Progress Summary: Retired

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Low NO_x Burners, Crist 6 & 7
PEs 1234, 1236, 1242, and 1284

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Low NO_x burners are unique burners installed to decrease the NO_x emissions that are formed in the combustion process. This equipment was installed to meet the requirements of the 1990 Clean Air Act Amendments.

Accomplishments:
The Low NO_x burner system has proven effective in reducing NO_x emissions. The low NO_x burners on Crist Unit 7 were replaced during 2003-2004 time frame and the Crist Unit 6 burners were replaced during December 2005.

Project-to-Date: Plant-in-service of $9,097,923 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: CEMs – Plant Crist, Scholz, Smith, and Daniel
PEs 1154, 1164, 1217, 1240, 1245, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1364, 1440, 1441, 1442, 1444, 1445, 1454, 1459, 1460, 1558, 1570, 1658, 1829, and 1830

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Continuous Emission Monitoring (CEM) line item includes dilution extraction emission monitors that measure the concentrations of sulfur dioxide (SO_2), carbon dioxide (CO_2) and nitrogen oxides (NO_x) in the flue gas. Opacity and flow monitors were also installed under this line item. All CEMs monitors were installed pursuant to the 1990 Clean Air Act Amendments (CAAA).

Accomplishments:
The systems at both Gulf and Mississippi Power continue to successfully exceed routine quality assurance/quality control (QA/QC) audits as required by the 1990 CAAA.

Project-to-Date: Plant-in-service of $5,001,633 projected at December 2008.

Progress Summary:
Crist 4, 5, 6 and 7 CEMS equipment replacements (gas analyzers, opacity monitors, and common CEMS equipment), Scholz 1 & 2 CEMS analyzer replacements, and Smith 1 gas analyzers and opacity monitor replacements were completed in 2001 and 2002. The Plant Crist Unit 6 & 7 and the Plant Scholz Units 1&2 flow monitors were replaced during 2005. The Plant Daniel Units 1&2 gas analyzers were replaced during 2005 and the flow monitors are subsequently being replaced during 2007.

Projections:
During the 2008 recovery period, the CEMs project includes the replacement of opacity, flow, and gas monitors at Plant Smith and opacity and gas monitors at Plant Scholz. The Plant Smith CEMs replacements were originally projected to be placed in service during December of 2007; however, this project has been delayed while Gulf evaluates the feasibility of moving the monitoring location from the air ducts to the stack. The existing monitors at Plants Smith and Scholz are approaching the end of their useful lives and will be retired upon replacement. The 2008 expenditures are expected to be approximately $1.0 million.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Substation Contamination Mobile Groundwater Treatment System
PEs 1007, 3400, and 3412

FPSC Approval: Order No. PSC-95-1051-FOF-EI

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: Plant-in-service of $918,024 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Raw Water Flow Meters - Crist and Smith
PEs 1155 and 1606

FPSC Approval: Order No. PSC-96-1171-FOF-EI

Description:
The Raw Water Flow Meters capital project was necessary for Gulf to comply with the Plant Crist and Plant Smith Consumptive Use and Individual Water Use permits issued by the Northwest Florida Water Management District (NWFWMD). These permits require the installation and monitoring of in-line totaling water flow meters on all existing and future water supply wells. Gulf incurred costs related to the installation and operation of new in-line totaling water flow meters at Plant Crist and Plant Smith for implementation of this new activity.

Accomplishments:
The raw water flow meters have been installed at Plant Crist and Plant Smith.

Project-to-Date: Plant-in-service of $242,943 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Cooling Tower Cell
PE 1232

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Crist Cooling Tower cell is a pollution control device which allows condenser cooling water to be continually reinjected into the condenser. The cooling tower reduces water discharge temperatures to meet the National Pollution Discharge Elimination System (NPDES) industrial wastewater requirements.

Accomplishments:
Plant Crist has maintained compliance with the temperature discharge limits as required by the facility's NPDES Permit. The cooling tower cell was retired during July 2007 when the new Crist Unit 7 cooling tower was placed in-service.

Project-to-Date: $0

Progress Summary: Retired

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist 1-5 Dechlorination
PE 1248

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
State and Federal Pollution Discharge Elimination System permits require significant reductions in chlorine discharge from the plant. The Crist Units 1-5 dechlorination system injects sodium bisulfite into the cooling water canal to chemically eliminate the residual chlorine present in the plant discharge effluent.

Accomplishments:
The system has been effective in maintaining chlorine discharge limits.

Project-to-Date: Plant-in-service of $305,323 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Diesel Fuel Oil Remediation
PE 1270

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
Monitoring wells were installed in the vicinity of the Crist diesel tank systems to determine if groundwater contamination was present. The project also included the installation of an impervious cap to reduce migration of contaminants to groundwater.

Accomplishments: Monitoring wells and an impervious cap were installed.

Project-to-Date: Plant-in-service of $68,923 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Bulk Tanker Unloading Secondary Containment
PE 1271

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The Crist Bulk Tanker Unloading Secondary Containment project was necessary to address deficiencies identified during the August 1992 Plant Crist Environmental Audit and to minimize the potential risk of an uncontrolled discharge of pollutants into the waters of the United States. Secondary containment must be installed for tank unloading racks pursuant to the Federal Spill Prevention Control and Countermeasures (SPCC) regulation (40 CFR Part 112).

Accomplishments:
The Plant Crist unloading area secondary containment complies with current SPCC regulatory requirements.

Project-to-Date: Plant-in-service of $101,495 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist IWW Sampling System
PE 1275

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The 1993 revision to Plant Crist's National Pollutant Discharge Elimination System (NPDES) industrial wastewater 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, an access dock was constructed in the discharge canal. The Crist Industrial Wastewater (IWW) project also included a small building for monitoring and sampling equipment.

Accomplishments:
The dock is complete and samples are collected at the required compliance point.

Project-to-Date: Plant-in-service of $59,543 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Sodium Injection System
PEs 1214 and 1413

FPSC Approval: Order No. PSC-99-1954-FOF-EI

Description:
The Sodium Injection System line item includes silo storage tank systems and associated components that inject sodium carbonate directly onto the coal feeder belt to enhance precipitator performance when burning low sulfur coal. Sodium injection is used at Plant Smith on Units 1 and 2 and at Plant Crist on Units 4 and 5. 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 injection system components at Plants Smith and Crist have been installed. These systems are fully operational.

Project-to-Date: Plant-in-service of $391,119 projected at December 2008.

Progress Summary: In Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Stormwater Collection System
PE 1446

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The National Pollutant Discharge Elimination System (NPDES) stormwater program requires industrial facilities to 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: Plant-in-service of $2,782,600 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Waste Water Treatment Facility
PEs 1466 and 1643

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
During the 1990's a waste water treatment facility was installed at Plant Smith to replace the septic tank system that was installed in the early 1960's. The system was designed to provide secondary treatment of raw sewage and domestic waste from the plant proper. The treatment included aeration, chlorination, and dechlorination of the wastewater prior to discharge. In April 2004 a new waste water treatment facility with additional capacity was installed to replace the facility installed in the 1990's. The existing treatment includes aeration and chlorination of the wastewater prior to discharging into the ash pond.

Accomplishments: Plant Smith has maintained compliance with the NPDES industrial wastewater permit.

Project-to-Date: Plant-in-service of $178,962 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Daniel Ash Management Project
PEs 1535, 1555, and 1819

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The original Daniel Ash Management Project included the installation of a dry ash transport system, lining the bottom of the ash pond, closure and capping of the existing fly ash pond, and the expansion of the landfill area. During 2006 plant Daniel completed construction of a new on-site ash storage facility in preparation for the completion and closure of the existing landfill area.

Accomplishments: No reportable exceedances have occurred since system installation. Construction of the new on-site ash storage facility was completed in 2006.

Project-to-Date: Plant-in-service of $15,236,945 projected at December 2008.

Progress Summary: In-Service

Projections:
Gulf expects to incur approximately $34,000 of additional capital expenditures during 2008 to complete construction of the stormwater management system.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Water Conservation
PEs 1620 and 1638

FPSC Approval: Order No. PSC-01-1788-FOF-EI

Description:
This project is a water conservation and consumptive use efficiency program to reduce the demand for groundwater and the potential for saltwater intrusion. Plant Smith's individual water use permit issued by the Northwest Florida Water Management District includes a specific condition requesting a 25% reduction in the use of groundwater. Phase I of the Smith Water Conservation project consisted of adding pumps, piping, valves and controls to reclaim water from the ash pond. Phase II, the Smith Closed Loop Cooling System was installed during 2005 to further reduce groundwater usage.

Accomplishments: Plant Smith estimated that the closed loop cooling project for the laboratory sampling system reduced water consumption by approximately 125,000 gallons per day.

Project-to-Date: Plant-in-service of $134,135 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Underground Fuel Tank Replacement
PE 4397

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Underground Fuel Tank Replacement Program provided for the replacement of all of Gulf's underground storage tanks with new above ground tanks. 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: $0

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist FDEP Agreement for Ozone Attainment

PEs 1031, 1199, 1250, and 1287

FPSC Approval: Order No. PSC-02-1396-FOF-EI

Description:
The Florida Department of Environmental Protection (FDEP) and Gulf Power entered into an agreement on August 28, 2002 to support Escambia/Santa Rosa County area's effort to maintain compliance with the 8-hour ozone ambient air quality standards. This agreement included a requirement for Gulf to install Selective Catalytic Reduction (SCR) controls on Crist Unit 7, relocate the Crist Unit 7 precipitator, and install a NO_x reduction technology on Plant Crist Unit 6, and Units 4 and 5 if necessary, to meet the NO_x standard specified in the Agreement.

Accomplishments: The Crist Unit 7 precipitator upgrade and SCR were placed in service during 2004 and 2005, respectively. The Crist Unit 6 Selective Non-Catalytic Reduction (SNCR)/low NOX burners with Over-Fired Air (OFA) technologies were then placed in service during November 2005. The Crist Unit 4 and Unit 5 SNCRs were subsequently placed in service during April 2006.

Project-to-Date: Plant-in-service of $136,206,437 projected at December 2008.

Progress Summary: In-Service

Projections: During 2008, Gulf will be replacing a layer of the SCR catalyst (PE 1031) and installing an additional ash vibrator system (PE 1250) to manage waste products associated with the operation of the SCR system on Crist Unit 7. The projected 2008 expenditures for the Crist FDEP Agreement projects are $2.15 million.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Storm Water Collection System
PE 1272

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
The Plant Crist Stormwater project was required as the 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 regulatory revision specifically included oil-containing electrical equipment within the scope of the regulation. Therefore, 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 was designed to route stormwater from the switchyard drains to the new oil skimming sump where any potential spill would be captured, preventing the oil from reaching surface water.

Accomplishments: Construction on the Plant Crist switchyard sump was completed during 2006.

Project-to-Date: Plant-in-service of $919,837 projected at December 2008.

Progress Summary: In-service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Common FTIR Monitor
PE 1297

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
The purchase of a Fourier Transform Infrared (FTIR) spectrometer, a device used to measure and analyze various low concentration stack gas emissions, was required at Plant Crist under Title V regulations. The purchase of this instrument enabled Gulf Power to measure ammonia slip emissions as required by the Crist Unit 7 Selective Catalytic Reduction (SCR) air construction permit.

Accomplishments: The FTIR is fully operational.

Project-to-Date: Plant-in-service of $62,870 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Precipitator Upgrades for Compliance Assurance Monitoring
PEs 1175, 1191, 1305, 1461, and 1462

FPSC Approval: Order No. PSC-04-1187-FOF-EI

Description: Compliance Assurance Monitoring (CAM) Precipitator Upgrades are required to comply with the new CAM regulations. CAM requirements are regulated under Title V of the 1990 Clean Air Act Amendments (CAAA) which requires a method of continuously monitoring particulate emissions. Opacity can be used as a surrogate parameter if the precipitator demonstrates a correlation between opacity and particulate matter. Gulf demonstrated this correlation by stack testing in 2003 and 2004, and the results were included as part of the CAM plans in Gulf's Title V Air Permits effective January 2005. The precipitator upgrades are necessary to meet the more stringent surrogate opacity standards under CAM.

Accomplishments: The Plant Smith Unit 2 and Unit 1 precipitator upgrades were placed in service during April 2005 and May 2007, respectively.

Project-to-Date: Plant-in-service of $29,369,841 projected at December 2008.

Progress Summary: See Accomplishments

Projections: Expenditures for precipitator upgrades were projected for Plant Scholz Unit 2 and Plant Crist Units 4 & 5 in 2007. The Scholz project will be placed in service during 2007, however the Crist projects will not be completed until 2008. Gulf's projected 2008 expenditures for CAM precipitator upgrades are $9.6 million.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant Groundwater Investigation
PEs 1218 and 1361

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description: The Florida Department of Environmental Protection (FDEP) lowered the arsenic groundwater standard from 0.05 mg/L to 0.01 mg/L effective January 1, 2005. Historical groundwater monitoring data from Plants Crist and Scholz indicated that these facilities may not be able to comply with the lower standard.

Accomplishments: The Plant Scholz project has been delayed until Gulf receives FDEP's formal response to the Plant Scholz groundwater study. The Plant Crist project was removed from the 2007 projection because Gulf has been released from any remedial action at this site.

Project-to-Date: $0

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant Crist Water Conservation Project
PE 1227

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description: This project is part of the Plant Crist water conservation and consumptive use efficiency program to reduce the demand for groundwater. Specific Condition six of the Northwest Florida Water Management District Individual Water Use Permit Number 19850074 issued January 27, 2005 requires Plant Crist to implement measures to increase water conservation and efficiency at the facility. Plant Crist will install automatic level controls on the fire water tanks during 2006 to reduce groundwater usage.

Accomplishments: Level controls were installed on the fire tank system during 2006.

Project-to-Date: Plant-in-service of $93,735 projected at December 2008.

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant NPDES Permit Compliance Projects
PE 1204 and 1299

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description: The water quality based copper effluent limitations included in Chapter 62 Part 302, Florida Administrative Code (F.A.C.) were amended in April 2002 with an effective date of May 2002. The more stringent hardness based standard is included by reference in the Plant Crist National Pollution Discharge Elimination System (NPDES) industrial wastewater permit.

Accomplishments: Plant Crist installed stainless steel condenser tubes on Unit 6 during June 2006 in an effort to meet the revised water quality standards during times of lower hardness in the river water.

Project-to-Date: Plant-in-service of $5,977,707 projected at December 2008.

Progress Summary: In-Service

Projections:
Gulf is conducting a study to identify solutions necessary to further reduce copper concentrations in the plant Crist discharge canal. Gulf expects to incur approximately $150,000 of expenditures during 2008 to help ensure compliance with the NPDES permit water quality standards. Solutions currently being considered include chemical treatment and/or aeration of either the oil skimmer pond or ash pond.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: CAIR / CAMR/CAVR Compliance Program
PEs 1034, 1035, 1036, 1037, 1095, 1222, 1362, 1468, 1469, 1512, 1513, 1646, 1647, 1684, 1810, 1824, and 1826

FPSC Approval: Order No. PSC-06-0972-FOF-EI and Stipulation approved by the Commission on August 14, 2007.

Description: This line item includes the prudently incurred costs for compliance with the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Clean Air Visibility Rule (CAVR). Gulf submitted its plan to achieve and maintain compliance with the CAIR, the CAMR, and the CAVR on March 29, 2007 pursuant to a process set out in Commission Order No. PSC-06-0972-FOF-EI. On June 22, 2007, the Office of Public Counsel ("OPC"), the Florida Industrial Power Users' Group ("FIPUG") and Gulf filed a petition for approval of a stipulation regarding the substantive provisions of Gulf's CAIR/CAMR/CAVR Compliance Plan. On August 14, 2007, the Commission voted to approve the stipulation with the provision that Gulf provide an annual status report regarding cost-effectiveness and prudence of the phases in its Plan that the Company is moving into.

Accomplishments: N/A

Project-to-Date: Plant-in-service of $54,438,841 projected at December 2008.

Progress Summary: See Accomplishments

Projections:
For the purpose of the 2008 projection of ECRC revenue requirements, expenditures totaling $23.5 million are projected to be incurred for capital projects included in the CAIR/CAMR/CAVR Compliance Program. These capital projects include installing Activated Carbon Injection (ACI) at Plant Daniel on Unit 2, Low NO_X burners at Plant Daniel on Units 1 and 2, Selective Non-Catalytic Reduction (SNCR) technologies at Plant Smith on Units 1 and 2, and mercury monitoring equipment.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: General Water Quality
PE 1280

FPSC Approval: Order No. PSC-06-0972-FOF-EI

Description: Gulf Power purchased a boat during 2007 for surface water sampling required by the Plants Crist, Smith and Scholz National Pollutant Discharge Elimination System (NPDES) permits. The permits have new conditions which require Gulf to establish a biological evaluation plan and implementation schedule for each plant.

Accomplishments: The General Water Quality sampling boat was purchased during 2007. It is currently being used to conduct Gulf's surface water sampling for Plants Crist, Smith, and Scholz.

Project-to-Date: Plant-in-service of $23,640 projected at December 2008.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Mercury Allowances

FPSC Approval: Stipulation approved by the Commission on August 14, 2007.

Description:
Although the retrofit installations set forth in Gulf's CAIR/CAMR/CAVR Compliance Program significantly reduce emissions, they will not result in Gulf achieving CAIR and CAMR compliance levels without the purchase of some emission allowances. Thus, Gulf's CAIR/CAMR/CAVR Compliance Program calls for the purchase of allowances. The purchase of allowances in conjunction with the retrofit projects comprises the most reasonable, cost-effective means for Gulf to meet CAIR, CAMR and CAVR requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary: N/A

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Annual NO_x Allowances

FPSC Approval: Stipulation approved by the Commission on August 14, 2007

Description:
Although the retrofit installations set forth in Gulf's CAIR/CAMR/CAVR Compliance Program significantly reduce emissions, they will not result in Gulf achieving CAIR and CAMR compliance levels without the purchase of some emission allowances. Thus, Gulf's CAIR/CAMR/CAVR Compliance Program calls for the purchase of allowances. The purchase of allowances in conjunction with the retrofit projects comprises the most reasonable, cost-effective means for Gulf to meet CAIR, CAMR and CAVR requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary: N/A

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Seasonal NO_x Allowances

FPSC Approval: Stipulation approved by the Commission on August 14, 2007

Description:
Although the retrofit installations set forth in Gulf's CAIR/CAMR/CAVR Compliance Program significantly reduce emissions, they will not result in Gulf achieving CAIR and CAMR compliance levels without the purchase of some emission allowances. Thus, Gulf's CAIR/CAMR/CAVR Compliance Program calls for the purchase of allowances. The purchase of allowances in conjunction with the retrofit projects comprises the most reasonable, cost-effective means for Gulf to meet CAIR, CAMR and CAVR requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary: N/A

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: SO_2 Allowances

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Part of Gulf's strategy to comply with the Clean Air Act Amendments of 1990 was to bring several of Gulf's Phase II generating units into compliance early and bank the SO_2 allowances associated with those units. This bank has slowly been drawn down over the years due to more allowances being consumed than are allocated to Gulf by EPA. Gulf proposed to meet this shortfall by executing forward contracts to secure allowances supplemented with forward contracts, swaps, and spot market purchases of allowances as prices dictate.

Accomplishments: Gulf secured additional allowances during 2007.

Project-to-Date: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.1

Title: Sulfur

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Crist Unit 7 sulfur trioxide (SO_3) flue gas system allowed for the injection of SO_3 into the flue gas stream. The addition of sulfur trioxide to the flue gas improved the collection efficiency of the precipitator when burning a low sulfur coal. Sulfur trioxide agglomerated the particles which in turn enhanced the collection efficiency of the precipitator.

Accomplishments:
The flue gas injection system was retired during 2005.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.2

Title: Air Emission Fees

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Air Emission Fees are the annual fees required by the Florida Department of Environmental Protection (FDEP) under Title IV of the Clean Air Act Amendments of 1990.

Accomplishments:
Fees have been paid by due dates.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $779,874

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.3

Title: Title V

FPSC Approval: Order No. PSC-95-0384-FOF-EI

Description:
Title V expenses are associated with the preparation of the Clean Air Act Amendments (CAAA) Title V permit applications and the subsequent implementation of Title V permits. Renewal of the Title V permits is on a five year cycle (i.e. 2005, 2010, etc).

Accomplishments:
Title V permits for Plants Crist, Smith, and Scholz were issued by FDEP in 1999. The Title V permit for the Pea Ridge Generating Facility was issued in July, 2000. During 2004, the Title V renewal applications were submitted for Plant Crist, Smith, and Scholz. The final permits were issued in December 2004 and February 2005.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $91,571

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.4

Title: Asbestos Fees

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
Asbestos Fees include both annual and individual project fees due to the Florida Department of Environmental Protection (FDEP) for asbestos abatement projects.

Accomplishments:
Fees are paid as required by FDEP.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $2,250

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.5

Title: Emission Monitoring

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Emission Monitoring program provides quality assurance/quality control testing for Continuous Emission Monitoring systems, including Relative Accuracy Test Audits and Linearity Tests as required by the Clean Air Act Amendments (CAAA) of 1990. Other activities within this category include testing for the Periodic Monitoring and Compliance Assurance Monitoring (CAM) requirements associated with the CAAA of 1990.

Accomplishments:
All systems are in compliance.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $663,054

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.6

Title: General Water Quality

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The General Water Quality activities are undertaken pursuant to the Company's NPDES permit, soil contamination studies, dechlorination, surface and groundwater monitoring studies, and the cooling water intake program. During 2004, the Cooling Water Intake Program and the new arsenic groundwater standard expenses were added to this line item.

Accomplishments:
All activities are on-going in compliance with all applicable environmental laws, rules, and regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $338,913

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.7

Title: Groundwater Contamination Investigation

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Groundwater Contamination Investigation project includes sampling and testing to determine possible environmental impacts to soil and groundwater from past herbicide applications at various substation sites. Once possible environmental impacts to groundwater and soils have been identified then cleanup operations are initiated.

Accomplishments:
The Florida Department of Environmental Protection has issued a No Further Action (NFA) letter for 41 sites.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,396,476

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.8

Title: State NPDES Administration

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
The State NPDES Administration fees are required by the State of Florida's National Pollutant Discharge Elimination System (NPDES) program administration. These annual fees are required for the renewal of NPDES industrial wastewater permits at Plants Crist, Smith and Scholz.

Accomplishments:
Gulf has complied with NPDES program administration fee submittal schedule.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $42,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.9

Title: Lead & Copper Rule

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
The Lead and Copper Rule expenses include potable water treatment and sampling costs for lead and copper as required by the Florida Department of Environmental Protection (FDEP) regulations.

Accomplishments:
Gulf has complied with all sampling and analytical protocols.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $21,500

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.10

Title: Environmental Auditing/Assessment

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Environmental Auditing/Assessment program ensures continued compliance with environmental laws, rules, and regulations through auditing and/or assessment of company facilities and operations.

Accomplishments:
Audits and assessments completed to date have demonstrated compliance with environmental laws, rules, and regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,300

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.11

Title: General Solid and Hazardous Waste

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The General Solid and Hazardous Waste 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 waste regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $331,185

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.12

Title: Above Ground Storage Tanks

FPSC Approval: Order No. PSC-97-1047-FOF-EI

Description:
The Above Ground Storage Tank projects are required under the provisions of Chapter 62-762, F.A.C. which includes specific performance standards applicable to storage tank systems. These performance standards include installation of secondary containment and cathodic protection systems as well as periodic tank integrity testing.

Accomplishments:
Gulf has complied with all applicable storage tank requirements.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $180,500

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.13

Title: Low NO_x

FPSC Approval: Order No. PSC-98-0803-FOF-EI

Description:
The Low NO_x activity refers to the maintenance expenses associated with the Low NO_x 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 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.14

Title: Ash Pond Diversion Curtains

FPSC Approval: Order No. PSC-98-1764-FOF-EI

Description:
The installation of additional flow diversion curtains in the Plant Crist ash pond were required to effectively increase water retention time in the ash pond. Diversion curtains allow for the sedimentation/precipitation treatment process to be more effective in reducing levels of suspended particulate from the Plant Crist ash pond outfall.

Accomplishments:
Ash pond diversion curtains have been installed at Plant Crist.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.15

Title: Mercury Emissions

FPSC Approval: Order No. PSC-99-0912-FOF-EI

Description: The Mercury Emissions program pertains to requirements for Gulf to periodically analyze coal shipments for mercury and chlorine content. The Environmental Protection Agency (EPA) mandated that shipments of coal would be analyzed for mercury and chlorine only during 1999. No further notices of continued sampling requirements of coal shipments beyond 1999 have been issued by EPA, therefore no expenses have been planned for this activity in 2007.

Accomplishments:
Coal shipments were analyzed as required during 1999. Sampling and analytical requirements are not expected during 2008.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.16

Title: Sodium Injection

FPSC Approval: Order No. PSC-99-1954-FOF-EI

Description:
This project refers to the sodium injection systems at Plant Smith and Plant Crist. The activity involves sodium injection to the coal supply to enhance precipitator efficiencies when burning low sulfur coal.

Accomplishments:
Sodium carbonate injection is used at Plant Smith and Plant Crist as necessary when low sulfur coal is burned.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $238,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.17

Title: Gulf Coast Ozone Study (GCOS)

FPSC Approval: Order No. PSC-00-0476-FOF-EI

Description:
This project referred to Gulf's participation in the Gulf Coast Ozone Study (GCOS) which was 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 goal of the project was to develop strategies for ozone ambient air attainment to supplement the Florida Department of Environmental Protection (FDEP) studies to the Environmental Protection Agency (EPA) for Escambia and Santa Rosa counties.

Accomplishments: The GCOS project was completed during 2006.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.18

Title: SPCC Substation Project

FPSC Approval: Order No. PSC-03-1348-FOF-EI

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 was 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: Gulf has assessed its substations to determine which are subject to the revised SPCC regulations. Additional containment has been added to the substations that were identified as having a reasonable risk of discharging oil into navigable waters of the United States or adjoining shorelines.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.19

Title: FDEP NO_x Reduction Agreement

FPSC Approval: Order No. PSC-02-1396-FOF-EI

Description: This line item includes the O&M expenses associated with the Crist Unit 7 Selective Catalytic Reduction (SCR) and Crist Units 4, 5, and 6 Selective Non-Catalytic Reduction (SNCR) projects that were included as part of the Florida Department of Environmental Protection (FDEP) and Gulf Power Agreement entered into on August 28, 2002. Anhydrous ammonia, urea, air monitoring, and general operation and maintenance expenses are included in this line item.

Accomplishments: The Crist Unit 7 SCR and the Crist Units 4, 5, and 6 SNCRs are fully operational.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $3,061,705

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2008-December 2008

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.20

Title: CAIR/CAMR/CAVR Compliance Plan

FPSC Approval: Order No. PSC-06-0972-FOF-EI and Stipulation approved by the Commission on August 14, 2007.

Description: This line item includes the O&M expenses associated with the stipulated portions of Gulf's CAIR, CAMR, and CAVR Compliance program. Gulf submitted its plan to achieve and maintain compliance with the CAIR, the CAMR, and the CAVR on March 29, 2007 pursuant to a process set out in Commission Order No. PSC-06-0972-FOF-EI. On June 22, 2007, the Office of Public Counsel ("OPC"), the Florida Industrial Power Users' Group ("FIPUG") and Gulf filed a petition for approval of a stipulation regarding the substantive provisions of Gulf's CAIR/CAMR/CAVR Compliance Plan. On August 14, 2007, the Commission voted to approve the stipulation with the provision that Gulf provide an annual status report regarding cost-effectiveness and prudence of the phases in its Plan that the Company is moving into.

Accomplishments: N/A

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: Gulf will begin incurring mercury monitoring O&M expenses during 2008 of $275,401.

Schedule 6P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2008 - December 2008

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Jan - Dec. 2008 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	58.020395%	5,632,024,000	1,108,101.93	1.0048648	1.0053010	5,661,879,190	1,113,492.58	48.40517%	57.53202%
GS	63.781436%	314,778,000	56,338.59	1.0048589	1.0052978	316,445,615	56,612.33	2.70539%	2.92505%
GSD, GSDT, GSTOU	75.860452%	2,615,948,000	393,649.38	1.0047057	1.0051660	2,629,462,092	395,501.76	22.48009%	20.43481%
LP, LPT	86.886296%	1,945,899,000	255,661.25	0.9842260	0.9891199	1,924,727,405	251,628.44	16.45509%	13.00115%
PX, PXT, RTP, SBS	104.683592%	1,044,432,000	113,893.11	0.9744382	0.9805725	1,024,141,329	110,981.79	8.75570%	5.73421%
OS-I/II	321.885641%	111,185,000	3,943.12	1.0046893	1.0052949	111,773,708	3,961.61	0.95559%	0.20469%
OS-III	99.718369%	28,271,000	3,236.40	1.0051151	1.0052683	28,419,939	3,252.95	0.24297%	0.16807%
TOTAL		11,692,537,000	1,934,823.78			11,696,849,278	1,935,431.46	100.00000%	100.00000%

Notes:
(1) Average 12 CP load factor based on actual 2006 load research data
(2) Projected KWH sales for the period January 2008 - December 2008
(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 Docket No. 010949-EI
(5) Based on energy losses identified in Docket No. 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

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2008 - December 2008

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	48.40517%	57.53202%	21,464,807	3,113,919	24,578,726	5,632,024,000	0.436
GS	2.70539%	2.92505%	1,199,679	158,318	1,357,997	314,778,000	0.431
GSD, GSDT, GSTOU	22.48009%	20.43481%	9,968,579	1,106,033	11,074,612	2,615,948,000	0.423
LP, LPT	16.45509%	13.00115%	7,296,851	703,687	8,000,538	1,945,899,000	0.411
PX, PXT, RTP, SBS	8.75570%	5.73421%	3,882,631	310,364	4,192,995	1,044,432,000	0.401
OS-I, OS-II	0.95559%	0.20469%	423,747	11,079	434,826	111,185,000	0.391
OS-III	0.24297%	0.16807%	107,743	9,097	116,840	28,271,000	0.413
TOTAL	100.00000%	100.00000%	$44,344,037	$5,412,497	$49,756,534	11,692,537,000	0.426

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 2008 - December 2008
(7) Col 5 / Col 6 x 100

DOCKET NO. 070007-EI
FINAL ECRC 2006 TRUE-UP
EXHIBIT HTB-1

TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

FINAL TRUE-UP AMOUNT FOR THE PERIOD OF JANUARY 2006 THROUGH DECEMBER 2006

FORMS 42-1A THROUGH 42-8A

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 43
COMPANY Tampa Electric Co.
WITNESS Howard T. Bryant (HTB-1
DATE 11-06-07

DOCKET NO. 070007-EI
FINAL ECRC 2006 TRUE-UP
EXHIBIT HTB-1

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TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

FINAL TRUE-UP AMOUNT FOR THE PERIOD OF JANUARY 2006 THROUGH DECEMBER 2006

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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 2006 to December 2006
(in Dollars)

Line		Period Amount
1.	End of Period Actual True-Up for the Period January 2006 to December 2006 (Form 42-2A, Lines 5 + 6 +10)	$46,451,725
2.	Estimated/Actual True-Up Amount Approved for the Period January 2006 to December 2006 (Order No. PSC-06-0972-FOF-EI)	58,347,408
3.	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2008 to December 2008 (Line 1-2)	($11,895,683)

DOCKET NO. 070007-EI
FINAL ECRC 2006 TRUE-UP
EXHIBIT HTB, DOCUMENT 1, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Form 42 - 2A

Current Period True-Up Amount
(in Dollars)

Line		January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	ECRC Revenues (net of Revenue Taxes)	($5,479,828)	($4,961,738)	($4,928,007)	($5,213,642)	($5,897,235)	($6,569,531)	($6,962,431)	($6,915,668)	($6,910,722)	($6,346,325)	($5,276,664)	($5,467,424)	($70,929,215)
2.	True-Up Provision	8,424,774	8,424,774	8,424,774	8,424,774	8,424,774	8,424,774	8,424,774	8,424,774	8,424,774	8,424,774	8,424,774	8,424,777	101,097,291
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	2,944,946	3,463,036	3,496,767	3,211,132	2,527,539	1,855,243	1,462,343	1,509,106	1,514,052	2,078,449	3,148,110	2,957,353	30,168,078
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	(31,161,586)	(5,699,263)	1,073,611	1,471,083	(213,103)	1,058,592	720,203	1,067,592	(2,160,724)	1,195,715	760,026	1,319,389	(30,568,465)
	b. Capital Investment Projects (Form 42-7A, Line 9)	1,446,774	1,470,116	1,466,431	1,472,115	1,485,710	1,481,709	1,479,114	1,466,403	1,481,401	1,480,912	1,469,139	1,484,658	17,684,483
	c. Total Jurisdictional ECRC Costs	(29,714,812)	(4,229,147)	2,540,042	2,943,198	1,272,607	2,540,301	2,199,317	2,533,995	(679,323)	2,676,627	2,229,165	2,804,047	(12,883,982)
5.	Over/Under Recovery (Line 3 - Line 4c)	32,659,758	7,692,183	956,725	267,934	1,254,932	(685,058)	(736,974)	(1,024,889)	2,193,376	(598,178)	918,945	153,306	43,052,060
6.	Interest Provision (Form 42-3A, Line 10)	329,006	383,513	380,282	367,749	345,624	323,847	296,045	255,466	219,860	187,342	151,538	117,650	3,357,922
7.	Beginning Balance True-Up & Interest Provision	101,097,291	125,703,024	125,353,946	118,266,179	110,477,088	103,652,870	94,866,884	86,001,181	76,806,984	70,795,446	61,959,835	54,605,544	101,097,291
	a. Deferred True-Up from January to December 2005 (Order No. PSC-06-0972-FOF-EI)	(23,609,173)	(23,609,173)	(23,609,173)	(23,609,173)	(23,609,173)	(23,609,173)	(23,609,173)	(23,609,173)	(23,609,173)	(23,609,173)	(23,609,173)	(23,609,173)	(23,609,173)
8.	True-Up Collected/(Refunded) (see Line 2)	(8,424,774)	(8,424,774)	(8,424,774)	(8,424,774)	(8,424,774)	(8,424,774)	(8,424,774)	(8,424,774)	(8,424,774)	(8,424,774)	(8,424,774)	(8,424,777)	(101,097,293)
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	102,052,108	101,744,773	94,657,006	86,867,915	80,043,697	71,257,711	62,392,008	53,197,811	47,186,273	38,350,662	30,996,371	22,842,550	22,800,807
10.	Adjustment to Period True-Up Including Interest	41,743	0	0	0	0	0	0	0	0	0	0	0	41,743
11.	End of Period Total True-Up (Lines 9 + 10)	$102,093,851	$101,744,773	$94,657,006	$86,867,915	$80,043,697	$71,257,711	$62,392,008	$53,197,811	$47,186,273	$38,350,662	$30,996,371	$22,842,550	$22,842,550

DOCKET NO. 070007-EI
FINAL ECRC 2006 TRUE-UP
EXHIBIT HTB, DOCUMENT 2, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Form 42 - 3A

Interest Provision
(in Dollars)

Line		January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$77,529,861	$102,093,851	$101,744,773	$94,657,006	$86,867,915	$80,043,697	$71,257,711	$62,392,008	$53,197,811	$47,186,273	$38,350,662	$30,996,371	
2.	Ending True-Up Amount Before Interest	101,764,845	101,361,260	94,276,724	86,500,166	79,698,073	70,933,865	62,095,963	52,942,345	46,966,413	38,163,321	30,844,833	22,724,900	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	179,294,706	203,455,111	196,021,497	181,157,172	166,565,988	150,977,562	133,353,674	115,334,353	100,164,224	85,349,594	69,195,495	53,721,271	
4.	Average True-Up Amount (Line 3 x 1/2)	89,647,353	101,727,556	98,010,749	90,578,586	83,282,994	75,488,781	66,676,837	57,667,177	50,082,112	42,674,797	34,597,748	26,860,636	
5.	Interest Rate (First Day of Reporting Business Month)	4.30%	4.51%	4.53%	4.78%	4.96%	5.01%	5.29%	5.36%	5.27%	5.26%	5.27%	5.25%	
6.	Interest Rate (First Day of Subsequent Business Month)	4.51%	4.53%	4.78%	4.96%	5.01%	5.29%	5.36%	5.27%	5.26%	5.27%	5.25%	5.27%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	8.81%	9.04%	9.31%	9.74%	9.97%	10.30%	10.65%	10.63%	10.53%	10.53%	10.52%	10.52%	
8.	Average Interest Rate (Line 7 x 1/2)	4.405%	4.520%	4.655%	4.870%	4.985%	5.150%	5.325%	5.315%	5.265%	5.265%	5.260%	5.260%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.367%	0.377%	0.388%	0.406%	0.415%	0.429%	0.444%	0.443%	0.439%	0.439%	0.438%	0.438%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$329,006	$383,513	$380,282	$367,749	$345,624	$323,847	$296,045	$255,466	$219,860	$187,342	$151,538	$117,650	$3,357,922

DOCKET NO. 070007-EI
FINAL ECRC 2006 TRUE-UP
EXHIBIT HTB, DOCUMENT 3, PAGE 1 OF 1

Form 42 - 4A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Variance Report of O & M Activities
(In Dollars)

Line		(1) Actual	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Variance Percent
1.	Description of O&M Activities				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$4,448,666	$4,138,858	$309,808	7.5%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	(44,690,220)	(57,818,437)	13,128,217	22.7%
	d. Big Bend Units 1 & 2 FGD	6,021,770	5,882,848	138,922	2.4%
	e. Big Bend PM Minimization and Monitoring	216,031	325,010	(108,979)	-33.5%
	f. Big Bend NO_x Emissions Reduction	803,946	850,647	(46,701)	-5.5%
	g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
	h. Gannon Thermal Discharge Study	107,868	85,123	22,745	26.7%
	i. Polk NO_x Emissions Reduction	44,196	40,100	4,096	10.2%
	j. Bayside SCR Consumables	68,089	64,644	3,445	5.3%
	k. Big Bend Unit 4 SOFA	11,638	11,638	0	0.0%
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0.0%
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0.0%
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0.0%
	o. Clean Water Act Section 316(b) Phase II Study	536,437	678,852	(142,415)	-21.0%
	p. Arsenic Groundwater Standard Program	11,406	5,595	5,811	103.9%
2.	Total Investment Projects - Recoverable Costs	($32,385,673)	($45,700,622)	$13,314,949	29.1%
3.	Recoverable Costs Allocated to Energy	($33,075,884)	($46,504,692)	$13,428,808	28.9%
4.	Recoverable Costs Allocated to Demand	$690,211	$804,070	($113,859)	-14.2%

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-06-0972-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Form 42 - 5A

O&M Activities
(in Dollars)

Line		January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$350,532	$412,304	$394,919	$552,336	$469,195	$387,486	$301,441	$386,024	$188,180	$301,677	$227,673	$476,899	$4,448,666		$4,448,666
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	(33,886,042)	(6,800,603)	50,518	45,425	(1,375,078)	50,157	1,678	24,740	(2,825,009)	(21,109)	26,351	18,752	(44,690,220)		(44,690,220)
	d. Big Bend Units 1 & 2 FGD	514,156	375,246	434,394	437,111	541,765	511,954	377,726	622,443	313,635	888,135	407,579	597,626	6,021,770		6,021,770
	e. Big Bend PM Minimization and Monitoring	960	14,604	13,497	34,797	27,214	16,048	12,023	14,741	11,399	24,930	33,236	12,582	216,031		216,031
	f. Big Bend NO_x Emissions Reduction	7,524	44,098	204,311	316,660	49,264	26,752	2,538	45,723	(46)	(6,232)	30,952	82,402	803,946		803,946
	g. NPDES Annual Surveillance Fees	34,500	0	0	0	0	0	0	0	0	0	0	0	34,500	34,500	
	h. Gannon Thermal Discharge Study	0	(338)	5,750	22,831	0	46,880	5,556	0	4,602	5,971	11,952	4,664	107,868	107,868	
	i. Polk NO_x Reduction	7,897	2,101	4,801	1,851	7,362	4,088	3,579	4,300	1,338	1,437	1,368	4,074	44,196		44,196
	j. Bayside SCR and Ammonia	0	0	8,896	0	18,187	9,061	0	7,876	8,365	0	15,704	0	68,089		68,089
	k. Big Bend Unit 4 SOFA	(158)	6,048	0	5,748	0	0	0	0	0	0	0	0	11,638		11,638
	l. Big Bend Unit 1 Pre-SCR	1,544	0	0	0	0	(1,544)	0	0	0	0	0	0	0		0
	m. Big Bend Unit 2 Pre-SCR	2,070	1,065	1,677	2,751	224	(7,787)	0	300	0	1,600	2,444	(4,344)	0		0
	n. Big Bend Unit 3 Pre-SCR		0	0	0	0	0	0	0	0	0	0	0	0		0
	o. Clean Water Act Section 316(b) Phase II Study	3,822	(10,176)	0	110,707	41,309	48,454	37,677	0	75,410	34,797	29,421	165,016	536,437	536,437	
	p. Arsenic Groundwater Standard Program	0	0	4,111	0	1,484	0	0	1,400	2,380	0	2,031	0	11,406	11,406	
2.	Total of O&M Activities	(32,963,195)	(5,955,651)	1,122,874	1,530,217	(219,074)	1,091,549	742,218	1,107,547	(2,219,746)	1,231,206	788,711	1,357,671	(32,385,673)	$690,211	($33,075,884)
3.	Recoverable Costs Allocated to Energy	(33,001,517)	(5,945,137)	1,113,013	1,396,679	(261,867)	996,215	698,985	1,106,147	(2,302,138)	1,190,438	745,307	1,187,991	(33,075,884)		
4.	Recoverable Costs Allocated to Demand	38,322	(10,514)	9,861	133,538	42,793	95,334	43,233	1,400	82,392	40,768	43,404	169,680	690,211		
5.	Retail Energy Jurisdictional Factor	0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931			
6.	Retail Demand Jurisdictional Factor	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722			
7.	Jurisdictional Energy Recoverable Costs (A)	(31,198,535)	(5,689,126)	1,064,103	1,342,329	(254,363)	966,674	678,519	1,066,242	(2,240,164)	1,156,408	718,177	1,155,788	(31,233,948)		
8.	Jurisdictional Demand Recoverable Costs (B)	36,949	(10,137)	9,508	128,754	41,260	91,918	41,684	1,350	79,440	39,307	41,849	163,601	665,483		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	($31,161,586)	($5,699,263)	$1,073,611	$1,471,083	($213,103)	$1,058,592	$720,203	$1,067,592	($2,160,724)	$1,195,715	$760,026	$1,319,389	($30,568,465)		

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Form 42 - 6A

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

Line		(1) Actual	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Variance Percent
1.	Description of Investment Projects				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$895,837	$895,837	$0	0.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	535,835	535,835	0	0.0%
	c. Big Bend Unit 4 Continuous Emissions Monitors	92,437	92,437	0	0.0%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	59,079	59,079	0	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	97,166	97,166	0	0.0%
	f. Phillips Upgrade Tank # 1 for FDEP	6,652	6,652	0	0.0%
	g. Phillips Upgrade Tank # 4 for FDEP	10,451	10,451	0	0.0%
	h. Big Bend Unit 1 Classifier Replacement	160,930	160,930	0	0.0%
	i. Big Bend Unit 2 Classifier Replacement	121,578	121,578	0	0.0%
	j. Big Bend Section 114 Mercury Testing Platform	14,800	14,800	0	0.0%
	k. Big Bend Units 1 & 2 FGD	10,471,438	10,472,968	(1,530)	0.0%
	l. Big Bend FGD Optimization and Utilization	2,822,021	2,822,021	0	0.0%
	m. Big Bend NO_x Emissions Reduction	932,568	932,938	(370)	0.0%
	n. Big Bend PM Minimization and Monitoring	1,200,580	1,200,580	0	0.0%
	o. Polk NO_x Emissions Reduction	218,592	218,592	0	0.0%
	p. Big Bend Unit 4 SOFA	351,818	351,818	0	0.0%
	q. Big Bend Unit 1 Pre-SCR	160,765	164,335	(3,570)	-2.2%
	r. Big Bend Unit 2 Pre-SCR	185,917	185,917	0	0.0%
	s. Big Bend Unit 3 Pre-SCR	69,588	69,632	(44)	-0.1%
	t. Big Bend Unit 1 SCR	0	0	0	0.0%
	u. Big Bend Unit 2 SCR	0	0	0	0.0%
	v. Big Bend Unit 3 SCR	0	0	0	0.0%
	w. Big Bend Unit 4 SCR	0	0	0	0.0%
	x. Big Bend FGD System Reliability	34,238	39,435	(5,197)	-13.2%
	y. SO_2 Emissions Allowances	(110,920)	(108,967)	(1,953)	1.8%
2.	Total Investment Projects - Recoverable Costs	$18,331,370	$18,344,034	($12,664)	-0.1%
3.	Recoverable Costs Allocated to Energy	$18,158,022	$18,170,686	($12,664)	-0.1%
4.	Recoverable Costs Allocated to Demand	$173,348	$173,348	$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-06-0972-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Form 42-7A

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		Description (A)	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$75,679	$75,492	$75,306	$75,120	$74,933	$74,746	$74,560	$74,373	$74,187	$74,000	$73,814	$73,627	$895,837		$895,837
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	45,532	45,373	45,213	45,052	44,892	44,733	44,573	44,413	44,254	44,094	43,933	43,773	535,835		535,835
	c.	Big Bend Unit 4 Continuous Emissions Monitors	7,807	7,788	7,770	7,750	7,731	7,713	7,693	7,675	7,656	7,637	7,618	7,599	92,437		92,437
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,981	4,971	4,960	4,950	4,939	4,929	4,918	4,907	4,897	4,886	4,876	4,865	59,079	$ 59,079	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	8,192	8,174	8,157	8,140	8,123	8,106	8,089	8,071	8,054	8,037	8,020	8,003	97,166	97,166	
	f.	Phillips Upgrade Tank # 1 for FDEP	563	562	559	558	557	555	554	552	550	549	547	546	6,652	6,652	
	g.	Phillips Upgrade Tank # 4 for FDEP	884	882	880	877	874	872	869	868	865	863	860	857	10,451	10,451	
	h.	Big Bend Unit 1 Classifier Replacement	13,633	13,593	13,553	13,512	13,471	13,431	13,391	13,350	13,310	13,269	13,228	13,189	160,930		160,930
	i.	Big Bend Unit 2 Classifier Replacement	10,311	10,278	10,245	10,214	10,181	10,148	10,115	10,083	10,050	10,017	9,984	9,952	121,578		121,578
	j.	Big Bend Section 114 Mercury Testing Platform	1,246	1,243	1,242	1,239	1,237	1,234	1,232	1,230	1,227	1,226	1,223	1,221	14,800		14,800
	k.	Big Bend Units 1 & 2 FGD	887,186	884,424	881,673	878,924	876,170	873,433	870,714	868,326	865,977	863,842	861,722	859,047	10,471,438		10,471,438
	l.	Big Bend FGD Optimization and Utilization	237,874	237,383	236,890	236,398	235,906	235,414	234,923	234,431	233,939	233,446	232,954	232,463	2,822,021		2,822,021
	m.	Big Bend NO_x Emissions Reduction	69,560	79,483	79,282	79,051	78,834	78,637	78,442	78,247	78,051	77,856	77,661	77,464	932,568		932,568
	n.	Big Bend PM Minimization and Monitoring	101,420	101,171	100,921	100,672	100,422	100,173	99,924	99,674	99,425	99,175	98,926	98,677	1,200,580		1,200,580
	o.	Polk NO_x Emissions Reduction	18,445	18,403	18,362	18,320	18,279	18,237	18,195	18,154	18,112	18,070	18,028	17,987	218,592		218,592
	p.	Big Bend Unit 4 SOFA	29,615	29,561	29,506	29,452	29,399	29,345	29,291	29,237	29,184	29,130	29,076	29,022	351,818		351,818
	q.	Big Bend Unit 1 Pre-SCR	9,461	9,527	9,601	9,663	11,119	12,580	12,555	12,483	15,483	19,064	19,630	19,599	160,765		160,765
	r.	Big Bend Unit 2 Pre-SCR	15,648	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	185,917		185,917
	s.	Big Bend Unit 3 Pre-SCR	2,258	2,388	3,898	6,000	6,708	6,849	6,912	6,924	6,923	6,923	6,909	6,896	69,588		69,588
	t.	Big Bend Unit 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	u.	Big Bend Unit 2 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	v.	Big Bend Unit 3 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	w.	Big Bend Unit 4 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	x.	Big Bend FGD System Reliability	0	0	0	0	0	0	722	1,921	3,799	5,497	8,303	13,996	34,238		34,238
	y.	SO_2 Emissions Allowances (B)	(10,202)	(10,014)	(9,787)	(9,698)	(9,605)	(9,532)	(9,324)	(9,117)	(8,907)	(8,461)	(8,163)	(8,110)	(110,920)		(110,920)
2.		Total Investment Projects - Recoverable Costs	1,530,093	1,536,161	1,533,710	1,531,673	1,529,649	1,527,082	1,523,827	1,521,281	1,522,515	1,524,599	1,524,628	1,526,152	16,351,405	$ 173,348	$ 18,158,022
3.		Recoverable Costs Allocated to Energy	1,515,473	1,521,572	1,519,154	1,517,148	1,515,156	1,512,620	1,509,397	1,506,883	1,508,149	1,510,264	1,510,325	1,511,881	18,158,022		
4.		Recoverable Costs Allocated to Demand	14,620	14,589	14,556	14,525	14,493	14,462	14,430	14,398	14,366	14,335	14,303	14,271	173,348		
5.		Retail Energy Jurisdictional Factor	0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931			
6.		Retail Demand Jurisdictional Factor	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722			
7.		Jurisdictional Energy Recoverable Costs (C)	1,432,678	1,456,050	1,452,396	1,458,110	1,471,737	1,467,765	1,465,201	1,452,521	1,467,549	1,467,091	1,455,348	1,470,899	17,517,346		
8.		Jurisdictional Demand Recoverable Costs (D)	14,096	14,066	14,034	14,005	13,974	13,944	13,913	13,882	13,851	13,821	13,791	13,760	167,137		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$1,446,774	$1,470,116	$1,466,431	$1,472,115	$1,485,710	$1,481,709	$1,479,114	$1,466,403	$1,481,401	$1,480,912	$1,469,139	$1,484,658	$17,684,483		

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

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	January	February	March	April	May	June	July	August	September	October	November	December	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	(2,412,033)	(2,431,259)	(2,450,485)	(2,469,711)	(2,488,937)	(2,508,163)	(2,527,389)	(2,546,615)	(2,565,841)	(2,585,067)	(2,604,293)	(2,623,519)	(2,642,745)	
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)	$5,827,625	5,808,399	5,789,173	5,769,947	5,750,721	5,731,495	5,712,269	5,693,043	5,673,817	5,654,591	5,635,365	5,616,139	5,596,913	
6.	Average Net Investment		5,818,012	5,798,786	5,779,560	5,760,334	5,741,108	5,721,882	5,702,656	5,683,430	5,664,204	5,644,978	5,625,752	5,606,526	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		42,781	42,639	42,498	42,357	42,215	42,074	41,933	41,791	41,650	41,508	41,367	41,226	$504,039
	b. Debt Component (Line 6 x 2.82% x 1/12)		13,672	13,627	13,582	13,537	13,492	13,446	13,401	13,356	13,311	13,266	13,221	13,175	161,086
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)		75,679	75,492	75,306	75,120	74,933	74,746	74,560	74,373	74,187	74,000	73,814	73,627	895,837
	a. Recoverable Costs Allocated to Energy		75,679	75,492	75,306	75,120	74,933	74,746	74,560	74,373	74,187	74,000	73,814	73,627	895,837
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		71,544	72,241	71,997	72,197	72,786	72,530	72,377	71,690	72,190	71,885	71,127	71,631	864,195
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)		$71,544	$72,241	$71,997	$72,197	$72,786	$72,530	$72,377	$71,690	$72,190	$71,885	$71,127	$71,631	$864,195

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

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	January	February	March	April	May	June	July	August	September	October	November	December	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	(2,014,886)	(2,031,361)	(2,047,836)	(2,064,311)	(2,080,786)	(2,097,261)	(2,113,736)	(2,130,211)	(2,146,686)	(2,163,161)	(2,179,636)	(2,196,111)	(2,212,586)	
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)	$3,002,848	2,986,373	2,969,898	2,953,423	2,936,948	2,920,473	2,903,998	2,887,523	2,871,048	2,854,573	2,838,098	2,821,623	2,805,148	
6.	Average Net Investment		2,994,611	2,978,136	2,961,661	2,945,186	2,928,711	2,912,236	2,895,761	2,879,286	2,862,811	2,846,336	2,829,861	2,813,386	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		22,020	21,899	21,778	21,656	21,535	21,414	21,293	21,172	21,051	20,930	20,808	20,687	$256,243
	b. Debt Component (Line 6 x 2.82% x 1/12)		7,037	6,999	6,960	6,921	6,882	6,844	6,805	6,766	6,728	6,689	6,650	6,611	81,892
8.	Investment Expenses														
	a. Depreciation (C)		16,475	16,475	16,475	16,475	16,475	16,475	16,475	16,475	16,475	16,475	16,475	16,475	197,700
	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)		45,532	45,373	45,213	45,052	44,892	44,733	44,573	44,413	44,254	44,094	43,933	43,773	535,835
	a. Recoverable Costs Allocated to Energy		45,532	45,373	45,213	45,052	44,892	44,733	44,573	44,413	44,254	44,094	43,933	43,773	535,835
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		43,044	43,419	43,226	43,299	43,606	43,407	43,268	42,811	43,063	42,834	42,334	42,586	516,897
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)		$43,044	$43,419	$43,226	$43,299	$43,606	$43,407	$43,268	$42,811	$43,063	$42,834	$42,334	$42,586	$516,897

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(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 3.8% and 4.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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FINAL ECRC 2006 TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	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	(261,497)	(263,446)	(265,395)	(267,344)	(269,293)	(271,242)	(273,191)	(275,140)	(277,089)	(279,038)	(280,987)	(282,936)	(284,885)	
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)	$604,714	602,765	600,816	598,867	596,918	594,969	593,020	591,071	589,122	587,173	585,224	583,275	581,326	
6.	Average Net Investment		603,740	601,791	599,842	597,893	595,944	593,995	592,046	590,097	588,148	586,199	584,250	582,301	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		4,439	4,425	4,411	4,396	4,382	4,368	4,353	4,339	4,325	4,310	4,296	4,282	$52,326
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,419	1,414	1,410	1,405	1,400	1,396	1,391	1,387	1,382	1,378	1,373	1,368	16,723
8.	Investment Expenses														
	a. Depreciation (D)		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)		7,807	7,788	7,770	7,750	7,731	7,713	7,693	7,675	7,656	7,637	7,618	7,599	92,437
	a. Recoverable Costs Allocated to Energy		7,807	7,788	7,770	7,750	7,731	7,713	7,693	7,675	7,656	7,637	7,618	7,599	92,437
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (E)		7,380	7,453	7,429	7,448	7,509	7,484	7,468	7,398	7,450	7,419	7,341	7,393	89,172
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)		$7,380	$7,453	$7,429	$7,448	$7,509	$7,484	$7,468	$7,398	$7,450	$7,419	$7,341	$7,393	$89,172

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 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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FINAL ECRC 2006 TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	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	(94,816)	(95,894)	(96,972)	(98,050)	(99,128)	(100,206)	(101,284)	(102,362)	(103,440)	(104,518)	(105,596)	(106,674)	(107,752)	
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)	$402,762	401,684	400,606	399,528	398,450	397,372	396,294	395,216	394,138	393,060	391,982	390,904	389,826	
6.	Average Net Investment		402,223	401,145	400,067	398,989	397,911	396,833	395,755	394,677	393,599	392,521	391,443	390,365	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,958	2,950	2,942	2,934	2,926	2,918	2,910	2,902	2,894	2,886	2,878	2,870	$34,968
	b. Debt Component (Line 6 x 2.82% x 1/12)		945	943	940	938	935	933	930	927	925	922	920	917	11,175
8.	Investment Expenses														
	a. Depreciation (C)		1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	12,936
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,981	4,971	4,960	4,950	4,939	4,929	4,918	4,907	4,897	4,886	4,876	4,865	59,079
	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		4,981	4,971	4,960	4,950	4,939	4,929	4,918	4,907	4,897	4,886	4,876	4,865	59,079
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		4,803	4,793	4,782	4,773	4,762	4,752	4,742	4,731	4,722	4,711	4,701	4,691	56,963
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,803	$4,793	$4,782	$4,773	$4,762	$4,752	$4,742	$4,731	$4,722	$4,711	$4,701	$4,691	$56,963

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 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	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	(155,968)	(157,741)	(159,514)	(161,287)	(163,060)	(164,833)	(166,606)	(168,379)	(170,152)	(171,925)	(173,698)	(175,471)	(177,244)	
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)	$662,433	660,660	658,887	657,114	655,341	653,568	651,795	650,022	648,249	646,476	644,703	642,930	641,157	
6.	Average Net Investment		661,547	659,774	658,001	656,228	654,455	652,682	650,909	649,136	647,363	645,590	643,817	642,044	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,864	4,851	4,838	4,825	4,812	4,799	4,786	4,773	4,760	4,747	4,734	4,721	$57,510
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,555	1,550	1,546	1,542	1,538	1,534	1,530	1,525	1,521	1,517	1,513	1,509	18,380
8.	Investment Expenses														
	a. Depreciation (C)		1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	21,276
	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)		8,192	8,174	8,157	8,140	8,123	8,106	8,089	8,071	8,054	8,037	8,020	8,003	97,166
	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		8,192	8,174	8,157	8,140	8,123	8,106	8,089	8,071	8,054	8,037	8,020	8,003	97,166
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		7,898	7,881	7,865	7,848	7,832	7,816	7,799	7,782	7,765	7,749	7,733	7,716	93,684
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,898	$7,881	$7,865	$7,848	$7,832	$7,816	$7,799	$7,782	$7,765	$7,749	$7,733	$7,716	$93,684

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 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 1 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	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	(15,492)	(15,650)	(15,808)	(15,966)	(16,124)	(16,282)	(16,440)	(16,598)	(16,756)	(16,914)	(17,072)	(17,230)	(17,388)	
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)	$41,785	41,627	41,469	41,311	41,153	40,995	40,837	40,679	40,521	40,363	40,205	40,047	39,889	
6.	Average Net Investment		41,706	41,548	41,390	41,232	41,074	40,916	40,758	40,600	40,442	40,284	40,126	39,968	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		307	306	304	303	302	301	300	299	297	296	295	294	$3,604
	b. Debt Component (Line 6 x 2.82% x 1/12)		98	98	97	97	97	96	96	95	95	95	94	94	1,152
8.	Investment Expenses														
	a. Depreciation (C)		158	158	158	158	158	158	158	158	158	158	158	158	1,896
	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)		563	562	559	558	557	555	554	552	550	549	547	546	6,652
	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		563	562	559	558	557	555	554	552	550	549	547	546	6,652
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		543	542	539	538	537	535	534	532	530	529	527	526	6,412
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$543	$542	$539	$538	$537	$535	$534	$532	$530	$529	$527	$526	$6,412

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 3.3%
(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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 4 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	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	(24,887)	(25,136)	(25,385)	(25,634)	(25,883)	(26,132)	(26,381)	(26,630)	(26,879)	(27,128)	(27,377)	(27,626)	(27,875)	
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)	$65,585	65,336	65,087	64,838	64,589	64,340	64,091	63,842	63,593	63,344	63,095	62,846	62,597	
6.	Average Net Investment		65,461	65,212	64,963	64,714	64,465	64,216	63,967	63,718	63,469	63,220	62,971	62,722	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		481	480	478	476	474	472	470	469	467	465	463	461	$5,656
	b. Debt Component (Line 6 x 2.82% x 1/12)		154	153	153	152	151	151	150	150	149	149	148	147	1,807
8.	Investment Expenses														
	a. Depreciation (C)		249	249	249	249	249	249	249	249	249	249	249	249	2,988
	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)		884	882	880	877	874	872	869	868	865	863	860	857	10,451
	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		884	882	880	877	874	872	869	868	865	863	860	857	10,451
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		852	850	848	846	843	841	838	837	834	832	829	826	10,076
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$852	$850	$848	$846	$843	$841	$838	$837	$834	$832	$829	$826	$10,076

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 3.3%
(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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	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	(338,696)	(342,864)	(347,032)	(351,200)	(355,368)	(359,536)	(363,704)	(367,872)	(372,040)	(376,208)	(380,376)	(384,544)	(388,712)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$977,561	973,393	969,225	965,057	960,889	956,721	952,553	948,385	944,217	940,049	935,881	931,713	927,545	
6.	Average Net Investment		975,477	971,309	967,141	962,973	958,805	954,637	950,469	946,301	942,133	937,965	933,797	929,629	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		7,173	7,142	7,112	7,081	7,050	7,020	6,989	6,958	6,928	6,897	6,866	6,836	$84,052
	b. Debt Component (Line 6 x 2.82% x 1/12)		2,292	2,283	2,273	2,263	2,253	2,243	2,234	2,224	2,214	2,204	2,194	2,185	26,862
8.	Investment Expenses														
	a. Depreciation (C)		4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	50,016
	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)		13,633	13,593	13,553	13,512	13,471	13,431	13,391	13,350	13,310	13,269	13,228	13,189	160,930
	a. Recoverable Costs Allocated to Energy		13,633	13,593	13,553	13,512	13,471	13,431	13,391	13,350	13,310	13,269	13,228	13,189	160,930
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		12,888	13,008	12,957	12,986	13,085	13,033	12,999	12,868	12,952	12,890	12,746	12,831	155,243
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)		$12,888	$13,008	$12,957	$12,986	$13,085	$13,033	$12,999	$12,868	$12,952	$12,890	$12,746	$12,831	$155,243

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 3.8%
(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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	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	(267,258)	(270,623)	(273,988)	(277,353)	(280,718)	(284,083)	(287,448)	(290,813)	(294,178)	(297,543)	(300,908)	(304,273)	(307,638)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$717,536	714,171	710,806	707,441	704,076	700,711	697,346	693,981	690,616	687,251	683,886	680,521	677,156	
6.	Average Net Investment		715,854	712,489	709,124	705,759	702,394	699,029	695,664	692,299	688,934	685,569	682,204	678,839	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,264	5,239	5,214	5,190	5,165	5,140	5,115	5,091	5,066	5,041	5,016	4,992	$61,533
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,682	1,674	1,666	1,659	1,651	1,643	1,635	1,627	1,619	1,611	1,603	1,595	19,665
8.	Investment Expenses														
	a. Depreciation (C)		3,365	3,365	3,365	3,365	3,365	3,365	3,365	3,365	3,365	3,365	3,365	3,365	40,380
	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)		10,311	10,278	10,245	10,214	10,181	10,148	10,115	10,083	10,050	10,017	9,984	9,952	121,578
	a. Recoverable Costs Allocated to Energy		10,311	10,278	10,245	10,214	10,181	10,148	10,115	10,083	10,050	10,017	9,984	9,952	121,578
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		9,748	9,835	9,795	9,817	9,889	9,847	9,819	9,719	9,779	9,731	9,621	9,682	117,282
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)		$9,748	$9,835	$9,795	$9,817	$9,889	$9,847	$9,819	$9,719	$9,779	$9,731	$9,621	$9,682	$117,282

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 4.1%
(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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	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	(16,051)	(16,282)	(16,513)	(16,744)	(16,975)	(17,206)	(17,437)	(17,668)	(17,899)	(18,130)	(18,361)	(18,592)	(18,823)	
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)	$104,686	104,455	104,224	103,993	103,762	103,531	103,300	103,069	102,838	102,607	102,376	102,145	101,914	
6.	Average Net Investment		104,571	104,340	104,109	103,878	103,647	103,416	103,185	102,954	102,723	102,492	102,261	102,030	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		769	767	766	764	762	760	759	757	755	754	752	750	$9,115
	b. Debt Component (Line 6 x 2.82% x 1/12)		246	245	245	244	244	243	242	242	241	241	240	240	2,913
8.	Investment Expenses														
	a. Depreciation (C)		231	231	231	231	231	231	231	231	231	231	231	231	2,772
	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)		1,246	1,243	1,242	1,239	1,237	1,234	1,232	1,230	1,227	1,226	1,223	1,221	14,800
	a. Recoverable Costs Allocated to Energy		1,246	1,243	1,242	1,239	1,237	1,234	1,232	1,230	1,227	1,226	1,223	1,221	14,800
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		1,178	1,189	1,187	1,191	1,202	1,197	1,196	1,186	1,194	1,191	1,178	1,188	14,277
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)		$1,178	$1,189	$1,187	$1,191	$1,202	$1,197	$1,196	$1,186	$1,194	$1,191	$1,178	$1,188	$14,277

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 2.3%
(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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$2,121	$736	$852	$4,567	$4,123	$73,096	$12,150	$117,062	$15,306	$2,657	$232,670
	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)	$83,318,932	$83,318,932	$83,318,932	$83,318,932	$83,318,932	$83,318,932	$83,318,932	$83,318,932	$83,318,932	$83,318,932	$83,318,932	$83,318,932	$83,318,932	
3.	Less: Accumulated Depreciation	(21,082,075)	(21,366,748)	(21,651,421)	(21,936,094)	(22,220,767)	(22,505,440)	(22,790,113)	(23,074,786)	(23,359,459)	(23,644,132)	(23,928,805)	(24,213,478)	(24,498,151)	
4.	CWIP - Non-Interest Bearing	0	0	0	2,121	2,857	3,709	8,276	12,399	85,495	97,645	214,707	230,013	232,670	
5.	Net Investment (Lines 2 + 3 + 4)	$62,236,857	61,952,184	61,667,511	61,384,959	61,101,022	60,817,201	60,537,095	60,256,545	60,044,968	59,772,445	59,604,834	59,335,467	59,053,451	
6.	Average Net Investment		62,094,520	61,809,847	61,526,235	61,242,990	60,959,111	60,677,148	60,396,820	60,150,756	59,908,706	59,688,639	59,470,150	59,194,459	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		456,591	454,498	452,413	450,330	448,243	446,169	444,108	442,299	440,519	438,901	437,294	435,267	$5,346,632
	b. Debt Component (Line 6 x 2.82% x 1/12)		145,922	145,253	144,587	143,921	143,254	142,591	141,933	141,354	140,785	140,268	139,755	139,107	1,708,730
8.	Investment Expenses														
	a. Depreciation (C)		284,673	284,673	284,673	284,673	284,673	284,673	284,673	284,673	284,673	284,673	284,673	284,673	3,416,076
	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)		887,186	884,424	881,673	878,924	876,170	873,433	870,714	868,326	865,977	863,842	861,722	859,047	10,471,438
	a. Recoverable Costs Allocated to Energy		887,186	884,424	881,673	878,924	876,170	873,433	870,714	868,326	865,977	863,842	861,722	859,047	10,471,438
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		838,716	846,339	842,929	844,722	851,062	847,533	845,219	837,000	842,665	839,148	830,355	835,761	10,101,449
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)		$838,716	$846,339	$842,929	$844,722	$851,062	$847,533	$845,219	$837,000	$842,665	$839,148	$830,355	$835,761	$10,101,449

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 4.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

DOCKET NO. 070007-EI
FINAL ECRC 2006 TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	
3.	Less: Accumulated Depreciation	(2,424,289)	(2,474,988)	(2,525,687)	(2,576,386)	(2,627,085)	(2,677,784)	(2,728,483)	(2,779,182)	(2,829,881)	(2,880,580)	(2,931,279)	(2,981,978)	(3,032,677)	
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)	$19,315,448	19,264,749	19,214,050	19,163,351	19,112,652	19,061,953	19,011,254	18,960,555	18,909,856	18,859,157	18,808,458	18,757,759	18,707,060	
6.	Average Net Investment		19,290,099	19,239,400	19,188,701	19,138,002	19,087,303	19,036,604	18,985,905	18,935,206	18,884,507	18,833,808	18,783,109	18,732,410	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		141,843	141,471	141,098	140,725	140,352	139,979	139,607	139,234	138,861	138,488	138,115	137,743	$1,677,516
	b. Debt Component (Line 6 x 2.82% x 1/12)		45,332	45,213	45,093	44,974	44,855	44,736	44,617	44,498	44,379	44,259	44,140	44,021	536,117
8.	Investment Expenses														
	a. Depreciation (D)		50,699	50,699	50,699	50,699	50,699	50,699	50,699	50,699	50,699	50,699	50,699	50,699	608,388
	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)		237,874	237,383	236,890	236,398	235,906	235,414	234,923	234,431	233,939	233,446	232,954	232,463	2,822,021
	a. Recoverable Costs Allocated to Energy		237,874	237,383	236,890	236,398	235,906	235,414	234,923	234,431	233,939	233,446	232,954	232,463	2,822,021
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (E)		224,878	227,161	226,480	227,199	229,146	228,433	228,044	225,974	227,641	226,773	224,474	226,162	2,722,365
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)		$224,878	$227,161	$226,480	$227,199	$229,146	$228,433	$228,044	$225,974	$227,641	$226,773	$224,474	$226,162	$2,722,365

Notes:

(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45 ($21,699,919)
(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 2.0% 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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		($4,471)	$1,198	($2,072)	($3,300)	$0	$0	$0	$0	$0	$0	$0	$0	($8,645)
	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	$6,132,384	$6,133,582	$6,131,510	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	
3.	Less: Accumulated Depreciation	0	(10,083)	(30,252)	(50,420)	(70,579)	(90,732)	(110,885)	(131,038)	(151,191)	(171,344)	(191,497)	(211,650)	(231,803)	
4.	CWIP - Non-Interest Bearing	6,136,855	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$6,136,855	6,122,301	6,103,330	6,081,090	6,057,631	6,037,478	6,017,325	5,997,172	5,977,019	5,956,866	5,936,713	5,916,560	5,896,407	
6.	Average Net Investment		6,129,578	6,112,816	6,092,210	6,069,361	6,047,555	6,027,402	6,007,249	5,987,096	5,966,943	5,946,790	5,926,637	5,906,484	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		45,072	44,949	44,797	44,629	44,469	44,320	44,172	44,024	43,876	43,728	43,580	43,431	$531,047
	b. Debt Component (Line 6 x 2.82% x 1/12)		14,405	14,365	14,317	14,263	14,212	14,164	14,117	14,070	14,022	13,975	13,928	13,880	169,718
8.	Investment Expenses														
	a. Depreciation (C)		10,083	20,169	20,168	20,159	20,153	20,153	20,153	20,153	20,153	20,153	20,153	20,153	231,803
	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)		69,560	79,483	79,282	79,051	78,834	78,637	78,442	78,247	78,051	77,856	77,661	77,464	932,568
	a. Recoverable Costs Allocated to Energy		69,560	79,483	79,282	79,051	78,834	78,637	78,442	78,247	78,051	77,856	77,661	77,464	932,568
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		65,760	76,060	75,798	75,975	76,575	76,305	76,145	75,424	75,950	75,630	74,834	75,364	899,820
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)		$65,760	$76,060	$75,798	$75,975	$76,575	$76,305	$76,145	$75,424	$75,950	$75,630	$74,834	$75,364	$899,820

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($4,013,075), and 312.43 ($439,964)
(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 3.8%, 4.1%, and 3.1%
(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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	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)	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	
3.	Less: Accumulated Depreciation	(175,167)	(200,873)	(226,579)	(252,285)	(277,991)	(303,697)	(329,403)	(355,109)	(380,815)	(406,521)	(432,227)	(457,933)	(483,639)	
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)	$7,815,885	7,790,179	7,764,473	7,738,767	7,713,061	7,687,355	7,661,649	7,635,943	7,610,237	7,584,531	7,558,825	7,533,119	7,507,413	
6.	Average Net Investment		7,803,032	7,777,326	7,751,620	7,725,914	7,700,208	7,674,502	7,648,796	7,623,090	7,597,384	7,571,678	7,545,972	7,520,266	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		57,377	57,188	56,999	56,810	56,621	56,432	56,243	56,054	55,865	55,676	55,487	55,298	$676,050
	b. Debt Component (Line 6 x 2.82% x 1/12)		18,337	18,277	18,216	18,156	18,095	18,035	17,975	17,914	17,854	17,793	17,733	17,673	216,058
8.	Investment Expenses														
	a. Depreciation (C)		25,706	25,706	25,706	25,706	25,706	25,706	25,706	25,706	25,706	25,706	25,706	25,706	308,472
	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)		101,420	101,171	100,921	100,672	100,422	100,173	99,924	99,674	99,425	99,175	98,926	98,677	1,200,580
	a. Recoverable Costs Allocated to Energy		101,420	101,171	100,921	100,672	100,422	100,173	99,924	99,674	99,425	99,175	98,926	98,677	1,200,580
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		95,879	96,814	96,486	96,754	97,544	97,203	96,998	96,078	96,748	96,340	95,325	96,002	1,158,171
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)		$95,879	$96,814	$96,486	$96,754	$97,544	$97,203	$96,998	$96,078	$96,748	$96,340	$95,325	$96,002	$1,158,171

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,513,263), 312.42 ($5,153,072), 312.43 ($955,619), 315.41 ($17,504), and 315.44 ($351,594)
(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 3.8%, 4.1%, 3.1%, 3.3%, and 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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(100,914)	(105,208)	(109,502)	(113,796)	(118,090)	(122,384)	(126,678)	(130,972)	(135,266)	(139,560)	(143,854)	(148,148)	(152,442)	
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)	$1,460,559	1,456,265	1,451,971	1,447,677	1,443,383	1,439,089	1,434,795	1,430,501	1,426,207	1,421,913	1,417,619	1,413,325	1,409,031	
6.	Average Net Investment		1,458,412	1,454,118	1,449,824	1,445,530	1,441,236	1,436,942	1,432,648	1,428,354	1,424,060	1,419,766	1,415,472	1,411,178	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,724	10,692	10,661	10,629	10,598	10,566	10,534	10,503	10,471	10,440	10,408	10,377	$126,603
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,427	3,417	3,407	3,397	3,387	3,377	3,367	3,357	3,347	3,336	3,326	3,316	40,461
8.	Investment Expenses														
	a. Depreciation (C)		4,294	4,294	4,294	4,294	4,294	4,294	4,294	4,294	4,294	4,294	4,294	4,294	51,528
	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)		18,445	18,403	18,362	18,320	18,279	18,237	18,195	18,154	18,112	18,070	18,028	17,987	218,592
	a. Recoverable Costs Allocated to Energy		18,445	18,403	18,362	18,320	18,279	18,237	18,195	18,154	18,112	18,070	18,028	17,987	218,592
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		17,437	17,611	17,555	17,607	17,755	17,696	17,662	17,499	17,624	17,553	17,372	17,499	210,870
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)		$17,437	$17,611	$17,555	$17,607	$17,755	$17,696	$17,662	$17,499	$17,624	$17,553	$17,372	$17,499	$210,870

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 3.3%
(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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(75,302)	(80,846)	(86,390)	(91,934)	(97,478)	(103,022)	(108,566)	(114,110)	(119,654)	(125,198)	(130,742)	(136,286)	(141,830)	
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)	$2,483,428	2,477,884	2,472,340	2,466,796	2,461,252	2,455,708	2,450,164	2,444,620	2,439,076	2,433,532	2,427,988	2,422,444	2,416,900	
6.	Average Net Investment		2,480,656	2,475,112	2,469,568	2,464,024	2,458,480	2,452,936	2,447,392	2,441,848	2,436,304	2,430,760	2,425,216	2,419,672	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		18,241	18,200	18,159	18,118	18,078	18,037	17,996	17,955	17,915	17,874	17,833	17,792	$216,198
	b. Debt Component (Line 6 x 2.82% x 1/12)		5,830	5,817	5,803	5,790	5,777	5,764	5,751	5,738	5,725	5,712	5,699	5,686	69,092
8.	Investment Expenses														
	a. Depreciation (C)		5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	66,528
	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)		29,615	29,561	29,506	29,452	29,399	29,345	29,291	29,237	29,184	29,130	29,076	29,022	351,818
	a. Recoverable Costs Allocated to Energy		29,615	29,561	29,506	29,452	29,399	29,345	29,291	29,237	29,184	29,130	29,076	29,022	351,818
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		27,997	28,288	28,209	28,306	28,557	28,475	28,433	28,182	28,398	28,297	28,018	28,235	339,395
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)		$27,997	$28,288	$28,209	$28,306	$28,557	$28,475	$28,433	$28,182	$28,398	$28,297	$28,018	$28,235	$339,395

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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$10,375	$3,192	$12,024	$968	$299,010	$2,048	($7,283)	($7,368)	$625,496	$112,955	$3,708	($10,302)	$1,044,823
	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	969,859	980,234	983,426	995,450	996,418	1,295,428	1,297,476	1,290,193	1,282,825	1,908,321	2,021,276	2,024,984	2,014,682	
5.	Net Investment (Lines 2 + 3 + 4)	$969,859	980,234	983,426	995,450	996,418	1,295,428	1,297,476	1,290,193	1,282,825	1,908,321	2,021,276	2,024,984	2,014,682	
6.	Average Net Investment		975,047	981,830	989,438	995,934	1,145,923	1,296,452	1,293,835	1,286,509	1,595,573	1,964,799	2,023,130	2,019,833	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		7,170	7,220	7,276	7,323	8,426	9,533	9,514	9,460	11,733	14,447	14,876	14,852	$121,830
	b. Debt Component (Line 6 x 2.82% x 1/12)		2,291	2,307	2,325	2,340	2,693	3,047	3,041	3,023	3,750	4,617	4,754	4,747	38,935
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)		9,461	9,527	9,601	9,663	11,119	12,580	12,555	12,483	15,483	19,064	19,630	19,599	160,765
	a. Recoverable Costs Allocated to Energy		9,461	9,527	9,601	9,663	11,119	12,580	12,555	12,483	15,483	19,064	19,630	19,599	160,765
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		8,944	9,117	9,179	9,287	10,800	12,207	12,187	12,033	15,066	18,519	18,915	19,068	155,322
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)		$8,944	$9,117	$9,179	$9,287	$10,800	$12,207	$12,187	$12,033	$15,066	$18,519	$18,915	$19,068	$155,322

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 3.8%
(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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		($34,805)	$0	$9	$0	$0	$0	$0	$0	$0	$0	$0	$0	($34,796)
	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	1,630,000	1,595,195	1,595,195	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	
5.	Net Investment (Lines 2 + 3 + 4)	$1,630,000	1,595,195	1,595,195	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	
6.	Average Net Investment		1,612,598	1,595,195	1,595,200	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	1,595,204	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		11,858	11,730	11,730	11,730	11,730	11,730	11,730	11,730	11,730	11,730	11,730	11,730	$140,888
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,790	3,749	3,749	3,749	3,749	3,749	3,749	3,749	3,749	3,749	3,749	3,749	45,029
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)		15,648	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	185,917
	a. Recoverable Costs Allocated to Energy		15,648	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	15,479	185,917
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		14,793	14,812	14,799	14,877	15,035	15,020	15,026	14,921	15,062	15,037	14,916	15,059	179,357
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)		$14,793	$14,812	$14,799	$14,877	$15,035	$15,020	$15,026	$14,921	$15,062	$15,037	$14,916	$15,059	$179,357

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 4.1%
(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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$22,244	$4,601	$306,525	$126,848	$18,999	$10,064	$2,862	($288)	$0	$0	($2,731)	$0	$489,124
	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	221,594	243,838	248,439	554,964	681,812	700,811	710,875	713,737	713,449	713,449	713,449	710,718	710,718	
5.	Net Investment (Lines 2 + 3 + 4)	$221,594	243,838	248,439	554,964	681,812	700,811	710,875	713,737	713,449	713,449	713,449	710,718	710,718	
6.	Average Net Investment		232,716	246,139	401,702	618,388	691,312	705,843	712,306	713,593	713,449	713,449	712,084	710,718	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		1,711	1,810	2,954	4,547	5,083	5,190	5,238	5,247	5,246	5,246	5,236	5,226	$52,734
	b. Debt Component (Line 6 x 2.82% x 1/12)		547	578	944	1,453	1,625	1,659	1,674	1,677	1,677	1,677	1,673	1,670	16,854
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)		2,258	2,388	3,898	6,000	6,708	6,849	6,912	6,924	6,923	6,923	6,909	6,896	69,588
	a. Recoverable Costs Allocated to Energy		2,258	2,388	3,898	6,000	6,708	6,849	6,912	6,924	6,923	6,923	6,909	6,896	69,588
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		2,135	2,285	3,727	5,767	6,516	6,646	6,710	6,674	6,737	6,725	6,658	6,709	67,289
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)		$2,135	$2,285	$3,727	$5,767	$6,516	$6,646	$6,710	$6,674	$6,737	$6,725	$6,658	$6,709	$67,289

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.1%
(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 Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$81,899	$100,471	$116,316	$105,636	$323,619	$417,999	$598,288	$305,866	$387,925	$759,767	$1,541,299	$1,612,657	$6,351,742
	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)	$1,153,135	$1,235,034	$1,335,505	$1,451,821	$1,557,457	$1,881,076	$2,299,075	$2,897,363	$3,203,229	$3,591,154	$4,350,921	$5,892,220	$7,504,877	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,153,135	1,235,034	1,335,505	1,451,821	1,557,457	1,881,076	2,299,075	2,897,363	3,203,229	3,591,154	4,350,921	5,892,220	7,504,877	
6.	Average Net Investment		1,194,085	1,285,270	1,393,663	1,504,639	1,719,267	2,090,076	2,598,219	3,050,296	3,397,192	3,971,038	5,121,571	6,698,549	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41 and 315.41. These dollars are for tracking purposes only; depreciation and return are not calculated until the project goes in to service.
(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% and 3.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$99,373	$160,300	$134,874	$181,106	$417,800	$486,989	$859,871	$563,785	$493,506	$1,021,051	$993,706	$750,437	$6,162,798
	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)	$1,472,016	$1,571,389	$1,731,689	$1,866,563	$2,047,669	$2,465,469	$2,952,458	$3,812,329	$4,376,114	$4,869,620	$5,890,671	$6,884,377	$7,634,814	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,472,016	1,571,389	1,731,689	1,866,563	2,047,669	2,465,469	2,952,458	3,812,329	4,376,114	4,869,620	5,890,671	6,884,377	7,634,814	
6.	Average Net Investment		1,521,703	1,651,539	1,799,126	1,957,116	2,256,569	2,708,964	3,382,394	4,094,222	4,622,867	5,380,146	6,387,524	7,259,596	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41 and 315.41. These dollars are for tracking purposes only; depreciation and return are not calculated until the project goes in to service.
(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 4.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

DOCKET NO. 070007-EI
FINAL ECRC 2006 TRUE-UP
EXHIBIT HTB, DOCUMENT 8, PAGE 21 OF 25

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$936,759	$1,987,940	$939,701	$2,047,962	$1,855,251	$2,697,646	$832,315	$1,735,467	$2,702,346	$3,042,677	$748,070	$2,625,503	$22,151,637
	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)	$6,715,872	$7,652,631	$9,640,571	$10,580,272	$12,628,234	$14,483,485	$17,181,131	$18,013,446	$19,748,913	$22,451,259	$25,493,936	$26,242,006	$28,867,509	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$6,715,872	7,652,631	9,640,571	10,580,272	12,628,234	14,483,485	17,181,131	18,013,446	19,748,913	22,451,259	25,493,936	26,242,006	28,867,509	
6.	Average Net Investment		7,184,252	8,646,601	10,110,422	11,604,253	13,555,860	15,832,308	17,597,289	18,881,180	21,100,086	23,972,598	25,867,971	27,554,758	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41 and 315.41. These dollars are for tracking purposes only; depreciation and return are not calculated until the project goes in to service.
(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 3.1%
(D) Line 9a x Line 10
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

DOCKET NO. 070007-EI
FINAL ECRC 2006 TRUE-UP
EXHIBIT HTB, DOCUMENT 8, PAGE 22 OF 25

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$4,317,092	$2,632,009	$2,718,067	$1,970,419	$1,448,458	$1,883,611	$4,794,336	$1,972,498	$2,128,398	$2,660,068	$3,278,434	$2,776,373	$32,579,763
	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)	$19,106,411	$23,423,503	$26,055,512	$28,773,579	$30,743,998	$32,192,456	$34,076,067	$38,870,403	$40,842,901	$42,971,299	$45,631,367	$48,909,801	$51,686,174	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$19,106,411	23,423,503	26,055,512	28,773,579	30,743,998	32,192,456	34,076,067	38,870,403	40,842,901	42,971,299	45,631,367	48,909,801	51,686,174	
6.	Average Net Investment		21,264,957	24,739,508	27,414,546	29,758,789	31,468,227	33,134,262	36,473,235	39,856,652	41,907,100	44,301,333	47,270,584	50,297,988	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41 and 315.41. These dollars are for tracking purposes only; depreciation and return are not calculated until the project goes in to service.
(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
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

DOCKET NO. 070007-EI
FINAL ECRC 2006 TRUE-UP
EXHIBIT HTB, DOCUMENT 8, PAGE 23 OF 25

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$148,727	$98,565	$288,614	$61,373	$516,942	$656,357	$1,770,578
	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	148,727	247,292	535,906	597,279	1,114,221	1,770,578	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	148,727	247,292	535,906	597,279	1,114,221	1,770,578	
6.	Average Net Investment		0	0	0	0	0	0	74,364	198,010	391,599	566,593	855,750	1,442,400	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	547	1,456	2,879	4,166	6,292	10,606	$25,946
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	175	465	920	1,331	2,011	3,390	8,292
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	722	1,921	3,799	5,497	8,303	13,996	34,238
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	722	1,921	3,799	5,497	8,303	13,996	34,238
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	701	1,852	3,697	5,340	8,001	13,617	33,208
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$701	$1,852	$3,697	$5,340	$8,001	$13,617	$33,208

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2006 to December 2006

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	January	February	March	April	May	June	July	August	September	October	November	December	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		33,720,625	6,807,500	(3,750)	0	0	0	0	0	2,836,500	(1,250)	0	0	$43,359,625
	c. Auction Proceeds/Other		218,195	0	0	0	1,404,977	0	0	0	0	0	0	0	$1,623,172
2.	Working Capital Balance														
	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 254.01 Regulatory Liabilities - Gains	(1,050,778)	(1,051,906)	(1,012,128)	(1,005,197)	(993,651)	(986,280)	(978,430)	(943,547)	(935,704)	(900,280)	(843,861)	(838,786)	(832,866)	
3.	Total Working Capital Balance	($1,050,778)	($1,051,906)	($1,012,128)	($1,005,197)	($993,651)	($986,280)	($978,430)	($943,547)	($935,704)	($900,280)	($843,861)	($838,786)	($832,866)	
4.	Average Net Working Capital Balance		($1,051,342)	($1,032,017)	($1,008,662)	($999,424)	($989,965)	($982,355)	($960,989)	($939,626)	($917,992)	($872,071)	($841,324)	($835,826)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($7,731)	($7,589)	($7,417)	($7,349)	($7,279)	($7,223)	($7,066)	($6,909)	($6,750)	($6,412)	($6,186)	($6,146)	($84,057)
	b. Debt Component (Line 4 x 2.82% x 1/12)		($2,471)	($2,425)	($2,370)	($2,349)	($2,326)	($2,309)	($2,258)	($2,208)	($2,157)	($2,049)	($1,977)	($1,964)	($26,863)
6.	Total Return Component		(10,202)	(10,014)	(9,787)	(9,698)	(9,605)	(9,532)	(9,324)	(9,117)	(8,907)	(8,461)	(8,163)	(8,110)	($110,920)
7.	Expenses:														
	a. Gains		(33,928,237)	(6,838,960)	3,750	0	(1,404,977)	0	0	0	(2,864,815)	1,250	0	0	(45,031,989)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		42,195	38,357	46,768	45,425	29,899	50,157	1,678	24,740	39,806	(22,359)	26,351	18,752	341,769
8.	Net Expenses (B)		(33,886,042)	(6,800,603)	50,518	45,425	(1,375,078)	50,157	1,678	24,740	(2,825,009)	(21,109)	26,351	18,752	(44,690,220)
9.	Total System Recoverable Expenses (Lines 6 + 8)		($33,896,244)	($6,810,617)	$40,731	$35,727	($1,384,683)	$40,625	($7,646)	$15,623	($2,833,916)	($29,570)	$18,188	$10,642	($44,801,140)
	a. Recoverable Costs Allocated to Energy		(33,896,244)	(6,810,617)	40,731	35,727	(1,384,683)	40,625	(7,646)	15,623	(2,833,916)	(29,570)	18,188	10,642	(44,801,140)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9453667	0.9569378	0.9560560	0.9610864	0.9713433	0.9703464	0.9707197	0.9639242	0.9730798	0.9714136	0.9635994	0.9728931	
11.	Demand Jurisdictional Factor		0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
12.	Retail Energy-Related Recoverable Costs (C)		(32,044,380)	(6,517,337)	38,941	34,337	(1,345,003)	39,420	(7,422)	15,059	(2,757,626)	(28,725)	17,526	10,354	(42,544,856)
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)		($32,044,380)	($6,517,337)	$38,941	$34,337	($1,345,003)	$39,420	($7,422)	$15,059	($2,757,626)	($28,725)	$17,526	$10,354	($42,544,856)

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 6 is reported on Schedule 6A and 7A
(C) Line 8 is reported on Schedule 4A and 5A
(D) Line 9a x Line 10
(E) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

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FINAL ECRC 2006 TRUE-UP
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DOCKET NO. 070007-EI
ECRC 2007 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2

TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL / ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD OF
JANUARY 2007 THROUGH DECEMBER 2007

FORMS 42-1E THROUGH 42-8E

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 44
COMPANY Tampa Electric Co.
WITNESS Howard T. Bryant (HTB-2)
DATE 11-06-07

DOCKET NO. 070007-EI
ECRC 2007 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2

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TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL / ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD OF
JANUARY 2007 THROUGH DECEMBER 2007

FORMS 42-1E THROUGH 42-8E

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Tampa Electric Company

Form 42 - 1E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
January 2007 to December 2007
(in Dollars)

Line		Period Amount
1.	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$9,704,423
2.	Interest Provision (Form 42-2E, Line 6)	(80,250)
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 2008 to December 2008 (Lines 1 + 2 + 3)	$9,624,173

Form 42 - 2E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

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 Total
1.	ECRC Revenues (net of Revenue Taxes)	($5,265,935)	($4,789,886)	($4,781,167)	($4,928,971)	($5,337,681)	($5,850,945)	($6,698,913)	($6,705,145)	($6,816,223)	($6,120,143)	($5,260,841)	($5,215,464)	($67,771,314)
2.	True-Up Provision	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,853	2,894,852	34,738,235
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	(2,371,082)	(1,895,033)	(1,886,314)	(2,034,118)	(2,442,828)	(2,956,092)	(3,804,060)	(3,810,292)	(3,921,370)	(3,225,290)	(2,365,988)	(2,320,612)	(33,033,080)
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	823,958	1,400,415	1,248,559	(188,756)	(11,253,862)	(3,092,906)	(5,534,531)	(9,512,003)	(9,563,672)	(9,514,021)	(9,664,912)	(9,701,396)	(64,553,127)
	b. Capital Investment Projects (Form 42-7A, Line 9)	1,385,233	1,371,847	1,400,704	1,390,507	1,566,905	2,097,636	2,088,733	2,080,810	2,090,615	2,086,588	2,124,747	2,131,300	21,815,625
	c. Total Jurisdictional ECRC Costs	2,209,191	2,772,262	2,649,263	1,201,751	(9,686,957)	(995,270)	(3,445,798)	(7,431,193)	(7,473,057)	(7,427,433)	(7,540,165)	(7,570,096)	(42,737,502)
5.	Over/Under Recovery (Line 3 - Line 4c)	(4,580,273)	(4,667,295)	(4,535,577)	(3,235,869)	7,244,129	(1,960,822)	(358,262)	3,620,901	3,551,687	4,202,143	5,174,177	5,249,484	9,704,423
6.	Interest Provision (Form 42-3A, Line 10)	83,871	51,116	18,506	(11,112)	(15,062)	(16,274)	(34,922)	(41,569)	(38,593)	(34,272)	(26,215)	(15,724)	(80,250)
7.	Beginning Balance True-Up & Interest Provision	34,738,235	27,346,980	19,835,948	12,424,024	6,282,190	10,616,404	5,744,455	2,456,418	3,140,897	3,759,138	5,032,156	7,285,265	34,738,235
	a. Deferred True-Up from January to December 2005 (Order No. PSC-xx-xxxx-FOF-EI)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)	(11,895,683)
8.	True-Up Collected/(Refunded) (see Line 2)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,853)	(2,894,852)	(34,738,235)
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	15,451,297	7,940,265	528,341	(5,613,493)	(1,279,279)	(6,151,228)	(9,439,265)	(8,754,786)	(8,136,545)	(6,863,527)	(4,610,418)	(2,271,510)	(2,271,510)
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 True-Up (Lines 9 + 10)	$15,451,297	$7,940,265	$528,341	($5,613,493)	($1,279,279)	($6,151,228)	($9,439,265)	($8,754,786)	($8,136,545)	($6,863,527)	($4,610,418)	($2,271,510)	($2,271,510)

DOCKET NO. 070007-EI
ECRC 2007 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT 2, PAGE 1 OF 1

Form 42 - 3E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

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 Total
1.	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$22,842,552	$15,451,297	$7,940,265	$528,341	($5,613,493)	($1,279,279)	($6,151,228)	($9,439,265)	($8,754,786)	($8,136,545)	($6,863,527)	($4,610,418)	
2.	Ending True-Up Amount Before Interest	15,367,426	7,889,149	509,835	(5,602,381)	(1,264,217)	(6,134,954)	(9,404,343)	(8,713,217)	(8,097,952)	(6,829,255)	(4,584,203)	(2,255,786)	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	38,209,978	23,340,446	8,450,100	(5,074,040)	(6,877,710)	(7,414,233)	(15,555,571)	(18,152,482)	(16,852,738)	(14,965,800)	(11,447,730)	(6,866,204)	
4.	Average True-Up Amount (Line 3 x 1/2)	19,104,989	11,670,223	4,225,050	(2,537,020)	(3,438,855)	(3,707,117)	(7,777,786)	(9,076,241)	(8,426,369)	(7,482,900)	(5,723,865)	(3,433,102)	
5.	Interest Rate (First Day of Reporting Business Month)	5.27%	5.26%	5.26%	5.26%	5.26%	5.26%	5.28%	5.50%	5.50%	5.50%	5.50%	5.50%	
6.	Interest Rate (First Day of Subsequent Business Month)	5.26%	5.26%	5.26%	5.26%	5.26%	5.28%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.53%	10.52%	10.52%	10.52%	10.52%	10.54%	10.78%	11.00%	11.00%	11.00%	11.00%	11.00%	
8.	Average Interest Rate (Line 7 x 1/2)	5.265%	5.260%	5.260%	5.260%	5.260%	5.270%	5.390%	5.500%	5.500%	5.500%	5.500%	5.500%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.439%	0.438%	0.438%	0.438%	0.438%	0.439%	0.449%	0.458%	0.458%	0.458%	0.458%	0.458%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$83,871	$51,116	$18,506	($11,112)	($15,062)	($16,274)	($34,922)	($41,569)	($38,593)	($34,272)	($26,215)	($15,724)	($80,250)

Tampa Electric Company Form 42 - 4E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

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				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$4,514,051	$ 4,013,300	$500,751	12.5%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	(79,602,597)	(74,041,987)	(5,560,610)	-7.5%
	d. Big Bend Units 1 & 2 FGD	5,477,691	6,621,900	(1,144,209)	-17.3%
	e. Big Bend PM Minimization and Monitoring	310,000	450,000	(140,000)	-31.1%
	f. Big Bend NO_x Emissions Reduction	490,000	350,000	140,000	40.0%
	g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
	h. Gannon Thermal Discharge Study	26,117	10,000	16,117	161.2%
	i. Polk NO_x Emissions Reduction	59,725	57,000	2,725	4.8%
	j. Bayside SCR Consumables	69,604	76,000	(6,396)	-8.4%
	k. Big Bend Unit 4 SOFA	220,000	250,000	(30,000)	-12.0%
	l. Big Bend Unit 1 Pre-SCR	0	75,000	(75,000)	-100.0%
	m. Big Bend Unit 2 Pre-SCR	15,000	75,000	(60,000)	-80.0%
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0.0%
	o. Clean Water Act Section 316(b) Phase II Study	396,758	736,192	(339,434)	-46.1%
	p. Arsenic Groundwater Standard Program	52,500	105,000	(52,500)	-50.0%
	q. Big Bend 4 SCR	759,873	1,256,000	(496,127)	-39.5%
2.	Total Investment Projects - Recoverable Costs	($67,176,778)	($59,932,095)	($7,244,683)	-12.1%
3.	Recoverable Costs Allocated to Energy	($67,686,653)	($60,817,787)	($6,868,866)	-11.3%
4.	Recoverable Costs Allocated to Demand	$509,875	$885,692	($375,817)	-42.4%

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-06-0972-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Form 42 - 5E

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 Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 Flue Gas Desulfunzation Integration	$299,597	$812,230	$367,415	$440,618	$271,213	$376,445	$335,592	$335,492	$332,726	$335,995	$313,091	$293,637	$4,514,051		$4,514,051
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	(25,909)	13,730	15,874	(1,028,135)	(12,470,078)	(4,077,470)	(6,805,761)	(11,044,348)	(11,045,680)	(11,043,657)	(11,046,762)	(11,044,401)	(79,602,597)		(79,602,597)
	d. Big Bend Units 1 & 2 FGD	615,331	290,459	312,229	459,151	372,698	358,403	489,007	502,351	521,771	531,399	504,861	520,031	5,477,691		5,477,691
	e. Big Bend PM Minimization and Monitoring	12,234	48,962	46,732	17,941	33,164	26,893	21,285	21,285	20,602	19,765	20,202	20,935	310,000		310,000
	f. Big Bend NO_x Emissions Reduction	15,319	128,663	324,729	(128,422)	14,248	11,196	(7,000)	61,500	8,000	8,000	34,000	19,767	490,000		490,000
	g. NPDES Annual Surveillance Fees	34,500	0	0	0	0	0	0	0	0	0	0	0	34,500	34,500	
	h. Gannon Thermal Discharge Study	4,902	6,031	4,850	1,725	977	7,632	0	0	0	0	0	0	26,117	26,117	
	i. Polk NO_x Reduction	2,588	2,142	6,840	3,394	12,833	10,325	3,500	3,500	3,300	3,403	4,400	3,500	59,725		59,725
	j. Bayside SCR and Ammonia	8,158	0	8,069	0	8,877	0	8,900	8,900	8,900		8,900	8,900	69,604		69,604
	k. Big Bend Unit 4 SOFA	0	9,844	159,897	(9,689)	2,977	0	0	0	0	26,000	30,971	0	220,000		220,000
	l. Big Bend Unit 1 Pre-SCR	543	0	0	0	0	(543)	0	0	0	0	0	0	0		0
	m. Big Bend Unit 2 Pre-SCR	1,100	0	2,710	0	5,713	(14,188)	15,665	0	0	0	4,000	0	15,000		15,000
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	o. Clean Water Act Section 316(b) Phase II Study	(124,116)	146,545	38,124	45,528	34,912	19,489	48,046	48,046	50,046	33,046	28,046	29,046	396,758	396,758	
	p. Arsenic Groundwater Standard Program	0	0	0	0	0	0	26,250	0	0	26,250	0	0	52,500	52,500	
	q. Big Bend 4 SCR	0	0	0	0	7,596	80,867	101,542	108,542	125,021	102,742	127,021	106,542	759,873		759,873
2.	Total of O&M Activities	844,247	1,458,606	1,287,469	(197,889)	(11,704,870)	(3,200,951)	(5,762,974)	(9,954,732)	(9,975,314)	(9,957,057)	(9,971,270)	(10,042,043)	(67,176,778)	$509,875	($67,686,653)
3.	Recoverable Costs Allocated to Energy	928,961	1,306,030	1,244,495	(245,142)	(11,740,759)	(3,228,072)	(5,837,270)	(10,002,778)	(10,025,360)	(10,016,353)	(9,999,316)	(10,071,089)	(67,686,653)		
4.	Recoverable Costs Allocated to Demand	(84,714)	152,576	42,974	47,253	35,889	27,121	74,296	48,046	50,046	59,296	28,046	29,046	509,875		
5.	Retail Energy Junsdictional Factor	0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796			
6.	Retail Demand Jurisdictional Factor	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743			
7.	Jurisdictional Energy Recoverable Costs (A)	905,849	1,252,924	1,207,017	(234,434)	(11,288,555)	(3,119,123)	(5,606,351)	(9,558,448)	(9,612,050)	(9,571,341)	(9,692,023)	(9,729,474)	(65,046,009)		
8.	Jurisdictional Demand Recoverable Costs (B)	(81,891)	147,491	41,542	45,678	34,693	26,217	71,820	46,445	48,378	57,320	27,111	28,078	492,882		
9.	Total Junsdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$823,958	$1,400,415	$1,248,559	($188,756)	($11,253,862)	($3,092,906)	($5,534,531)	($9,512,003)	($9,563,672)	($9,514,021)	($9,664,912)	($9,701,396)	($64,553,127)		

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

Form 42 - 6E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

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

Line		(1) Actual/Estimated	(2) Original Projection	(3) Variance Amount	(4) Percent
1.	Description of Investment Projects				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$830,177	$868,973	($38,796)	-4.5%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	478,165	512,817	(34,652)	-6.8%
	c. Big Bend Unit 4 Continuous Emissions Monitors	84,822	89,714	(4,892)	-5.5%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	57,574	57,574	0	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	94,694	94,694	0	0.0%
	f. Phillips Upgrade Tank # 1 for FDEP	6,262	6,430	(168)	-2.6%
	g. Phillips Upgrade Tank # 4 for FDEP	9,842	10,103	(261)	-2.6%
	h. Big Bend Unit 1 Classifier Replacement	148,910	155,105	(6,195)	-4.0%
	i. Big Bend Unit 2 Classifier Replacement	107,596	116,875	(9,279)	-7.9%
	j. Big Bend Section 114 Mercury Testing Platform	14,137	14,478	(341)	-2.4%
	k. Big Bend Units 1 & 2 FGD	9,156,955	10,119,550	(962,595)	-9.5%
	l. Big Bend FGD Optimization and Utilization	2,648,825	2,751,182	(102,357)	-3.7%
	m. Big Bend NO_x Emissions Reduction	866,806	921,526	(54,720)	-5.9%
	n. Big Bend PM Minimization and Monitoring	1,102,382	1,209,451	(107,069)	-8.9%
	o. Polk NO_x Emissions Reduction	214,062	212,592	1,470	0.7%
	p. Big Bend Unit 4 SOFA	339,250	344,073	(4,823)	-1.4%
	q. Big Bend Unit 1 Pre-SCR	283,636	332,519	(48,883)	-14.7%
	r. Big Bend Unit 2 Pre-SCR	228,630	244,914	(16,284)	-6.6%
	s. Big Bend Unit 3 Pre-SCR	133,737	162,123	(28,386)	-17.5%
	t. Big Bend Unit 1 SCR	0	0	0	0.0%
	u. Big Bend Unit 2 SCR	0	0	0	0.0%
	v. Big Bend Unit 3 SCR	0	0	0	0.0%
	w. Big Bend Unit 4 SCR	5,145,048	5,630,498	(485,450)	-8.6%
	x. Big Bend FGD System Reliability	778,808	906,108	(127,300)	-14.0%
	y. Clean Air Mercury Rule	0	30,226	(30,226)	-100.0%
	z. SO_2 Emissions Allowances	(66,968)	(5,548)	(61,420)	1107.1%
2.	Total Investment Projects - Recoverable Costs	$22,663,350	$24,785,977	($2,122,627)	-8.6%
3.	Recoverable Costs Allocated to Energy	$22,494,978	$24,617,176	($2,122,198)	-8.6%
4.	Recoverable Costs Allocated to Demand	$168,372	$168,801	($429)	-0.3%

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-06-0972-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-7E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line		Description (A)	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 Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$70,024	$69,871	$69,718	$69,565	$69,411	$69,258	$69,105	$68,951	$68,798	$68,645	$68,492	$68,339	$830,177		$830,177
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	40,562	40,433	40,302	40,173	40,042	39,912	39,782	39,652	39,522	39,392	39,261	39,132	478,165		478,165
	c.	Big Bend Unit 4 Continuous Emissions Monitors	7,149	7,135	7,120	7,106	7,090	7,076	7,061	7,046	7,032	7,017	7,003	6,987	84,822		84,822
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,855	4,845	4,835	4,824	4,814	4,803	4,793	4,782	4,772	4,761	4,750	4,740	57,574	$57,574	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,986	7,968	7,951	7,934	7,917	7,900	7,883	7,865	7,848	7,831	7,814	7,797	94,694	94,694	
	f.	Phillips Upgrade Tank # 1 for FDEP	530	528	527	526	524	523	521	519	518	517	515	514	6,262	6,262	
	g.	Phillips Upgrade Tank # 4 for FDEP	832	830	828	825	824	821	819	817	815	812	811	808	9,842	9,842	
	h.	Big Bend Unit 1 Classifier Replacement	12,602	12,567	12,532	12,497	12,462	12,427	12,391	12,357	12,321	12,287	12,251	12,216	148,910		148,910
	i.	Big Bend Unit 2 Classifier Replacement	9,102	9,077	9,052	9,028	9,003	8,978	8,954	8,929	8,905	8,881	8,856	8,831	107,596		107,596
	j.	Big Bend Section 114 Mercury Testing Platform	1,189	1,187	1,185	1,183	1,181	1,179	1,177	1,175	1,173	1,171	1,170	1,167	14,137		14,137
	k.	Big Bend Units 1 & 2 FGD	773,612	771,887	769,929	767,971	766,012	764,054	762,096	760,138	758,186	756,258	754,359	752,453	9,156,955		9,156,955
	l.	Big Bend FGD Optimization and Utilization	222,958	222,554	222,150	221,745	221,341	220,937	220,534	220,130	219,725	219,321	218,917	218,513	2,648,825		2,648,825
	m.	Big Bend NO_x Emissions Reduction	73,064	72,909	72,754	72,600	72,445	72,291	72,136	71,982	71,827	71,673	71,519	71,606	866,806		866,806
	n.	Big Bend PM Minimization and Monitoring	92,943	92,747	92,551	92,355	92,159	91,963	91,767	91,571	91,375	91,180	90,983	90,788	1,102,382		1,102,382
	o.	Polk NO_x Emissions Reduction	18,075	18,032	17,989	17,946	17,902	17,860	17,817	17,774	17,731	17,688	17,645	17,603	214,062		214,062
	p.	Big Bend Unit 4 SOFA	28,544	28,494	28,445	28,395	28,346	28,296	28,246	28,197	28,147	28,096	28,047	27,997	339,250		339,250
	q.	Big Bend Unit 1 Pre-SCR	21,814	24,031	23,966	23,928	23,887	23,846	23,804	23,760	23,716	23,672	23,628	23,584	283,636		283,636
	r.	Big Bend Unit 2 Pre-SCR	17,447	19,397	19,357	19,318	19,278	19,238	19,199	19,159	19,119	19,079	19,039	19,000	228,630		228,630
	s.	Big Bend Unit 3 Pre-SCR	7,225	7,552	7,865	8,214	8,249	8,246	8,273	10,190	12,533	13,871	18,274	23,245	133,737		133,737
	t.	Big Bend Unit 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	u.	Big Bend Unit 2 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	v.	Big Bend Unit 3 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	w.	Big Bend Unit 4 SCR	0	0	0	0	169,240	704,920	709,415	710,109	710,800	711,943	713,489	715,132	5,145,048		5,145,048
	x.	Big Bend FGD System Reliability	18,024	25,414	42,726	55,199	64,410	72,680	74,825	77,525	79,893	82,817	87,914	97,381	778,808		778,808
	y.	Clean Air Mercury Rule	0	0	0	0	0	0	0	0	0	0	0	0	0		0
		SO_2 Emissions Allowances (B)	(7,837)	(7,573)	(7,539)	(7,466)	(6,940)	(6,309)	(5,924)	(5,253)	(4,361)	(3,472)	(2,586)	(1,708)	(66,968)		(66,968)
2.		Total Investment Projects - Recoverable Costs	1,420,700	1,429,885	1,444,243	1,453,866	1,629,597	2,170,899	2,174,674	2,177,375	2,180,395	2,183,440	2,192,151	2,206,125	22,663,350	$168,372	$22,494,978
3.		Recoverable Costs Allocated to Energy	1,406,497	1,415,714	1,430,102	1,439,757	1,615,518	2,156,852	2,160,658	2,163,392	2,166,442	2,169,519	2,178,261	2,192,266	22,494,978		
4.		Recoverable Costs Allocated to Demand	14,203	14,171	14,141	14,109	14,079	14,047	14,016	13,983	13,953	13,921	13,890	13,859	168,372		
5.		Retail Energy Jurisdictional Factor	0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796			
6.		Retail Demand Jurisdictional Factor	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743			
7.		Jurisdictional Energy Recoverable Costs (C)	1,371,503	1,358,148	1,387,034	1,376,868	1,553,295	2,084,057	2,075,184	2,067,293	2,077,127	2,073,131	2,111,320	2,117,903	21,652,863		
8.		Jurisdictional Demand Recoverable Costs (D)	13,730	13,699	13,670	13,639	13,610	13,579	13,549	13,517	13,488	13,457	13,427	13,397	162,762		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$1,385,233	$1,371,847	$1,400,704	$1,390,507	$1,566,905	$2,097,636	$2,088,733	$2,080,810	$2,090,615	$2,086,588	$2,124,747	$2,131,300	$21,815,625		

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

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 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 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	(2,642,745)	(2,658,538)	(2,674,331)	(2,690,124)	(2,705,917)	(2,721,710)	(2,737,503)	(2,753,296)	(2,769,089)	(2,784,882)	(2,800,675)	(2,816,468)	(2,832,261)	
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)	$5,596,913	5,581,120	5,565,327	5,549,534	5,533,741	5,517,948	5,502,155	5,486,362	5,470,569	5,454,776	5,438,983	5,423,190	5,407,397	
6.	Average Net Investment		5,589,017	5,573,224	5,557,431	5,541,638	5,525,845	5,510,052	5,494,259	5,478,466	5,462,673	5,446,880	5,431,087	5,415,294	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		41,097	40,981	40,865	40,749	40,632	40,516	40,400	40,284	40,168	40,052	39,936	39,820	$485,500
	b. Debt Component (Line 6 x 2.82% x 1/12)		13,134	13,097	13,060	13,023	12,986	12,949	12,912	12,874	12,837	12,800	12,763	12,726	155,161
8.	Investment Expenses														
	a. Depreciation (C)		15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	189,516
	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)		70,024	69,871	69,718	69,565	69,411	69,258	69,105	68,951	68,798	68,645	68,492	68,339	830,177
	a. Recoverable Costs Allocated to Energy		70,024	69,871	69,718	69,565	69,411	69,258	69,105	68,951	68,798	68,645	68,492	68,339	830,177
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		68,282	67,030	67,618	66,526	66,738	66,921	66,371	65,888	65,962	65,595	66,387	66,021	799,339
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)		$68,282	$67,030	$67,618	$66,526	$66,738	$66,921	$66,371	$65,888	$65,962	$65,595	$66,387	$66,021	$799,339

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 2.3%
(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 2007 to December 2007

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 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 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	(2,212,586)	(2,225,995)	(2,239,404)	(2,252,813)	(2,266,222)	(2,279,631)	(2,293,040)	(2,306,449)	(2,319,858)	(2,333,267)	(2,346,676)	(2,360,085)	(2,373,494)	
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)	$2,805,148	2,791,739	2,778,330	2,764,921	2,751,512	2,738,103	2,724,694	2,711,285	2,697,876	2,684,467	2,671,058	2,657,649	2,644,240	
6.	Average Net Investment		2,798,444	2,785,035	2,771,626	2,758,217	2,744,808	2,731,399	2,717,990	2,704,581	2,691,172	2,677,763	2,664,354	2,650,945	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		20,577	20,479	20,380	20,282	20,183	20,084	19,986	19,887	19,789	19,690	19,591	19,493	$240,421
	b. Debt Component (Line 6 x 2.82% x 1/12)		6,576	6,545	6,513	6,482	6,450	6,419	6,387	6,356	6,324	6,293	6,261	6,230	76,836
8.	Investment Expenses														
	a. Depreciation (C)		13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	160,908
	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)		40,562	40,433	40,302	40,173	40,042	39,912	39,782	39,652	39,522	39,392	39,261	39,132	478,165
	a. Recoverable Costs Allocated to Energy		40,562	40,433	40,302	40,173	40,042	39,912	39,782	39,652	39,522	39,392	39,261	39,132	478,165
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		39,553	38,789	39,088	38,418	38,500	38,565	38,208	37,891	37,893	37,642	38,054	37,805	460,406
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)		$39,553	$38,789	$39,088	$38,418	$38,500	$38,565	$38,208	$37,891	$37,893	$37,642	$38,054	$37,805	$460,406

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(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 3.3% and 3.1%
(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 2007 to December 2007

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 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 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	(284,885)	(286,401)	(287,917)	(289,433)	(290,949)	(292,465)	(293,981)	(295,497)	(297,013)	(298,529)	(300,045)	(301,561)	(303,077)	
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)	$581,326	579,810	578,294	576,778	575,262	573,746	572,230	570,714	569,198	567,682	566,166	564,650	563,134	
6.	Average Net Investment		580,568	579,052	577,536	576,020	574,504	572,988	571,472	569,956	568,440	566,924	565,408	563,892	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,269	4,258	4,247	4,236	4,224	4,213	4,202	4,191	4,180	4,169	4,158	4,146	$50,493
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,364	1,361	1,357	1,354	1,350	1,347	1,343	1,339	1,336	1,332	1,329	1,325	16,137
8.	Investment Expenses														
	a. Depreciation (C)		1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	18,192
	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)		7,149	7,135	7,120	7,106	7,090	7,076	7,061	7,046	7,032	7,017	7,003	6,987	84,822
	a. Recoverable Costs Allocated to Energy		7,149	7,135	7,120	7,106	7,090	7,076	7,061	7,046	7,032	7,017	7,003	6,987	84,822
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		6,971	6,845	6,906	6,796	6,817	6,837	6,782	6,733	6,742	6,705	6,788	6,750	81,672
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)		$6,971	$6,845	$6,906	$6,796	$6,817	$6,837	$6,782	$6,733	$6,742	$6,705	$6,788	$6,750	$81,672

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 2.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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ECRC 2007 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

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 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 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	(107,752)	(108,830)	(109,908)	(110,986)	(112,064)	(113,142)	(114,220)	(115,298)	(116,376)	(117,454)	(118,532)	(119,610)	(120,688)	
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)	$389,826	388,748	387,670	386,592	385,514	384,436	383,358	382,280	381,202	380,124	379,046	377,968	376,890	
6.	Average Net Investment		389,287	388,209	387,131	386,053	384,975	383,897	382,819	381,741	380,663	379,585	378,507	377,429	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,862	2,855	2,847	2,839	2,831	2,823	2,815	2,807	2,799	2,791	2,783	2,775	$33,827
	b. Debt Component (Line 6 x 2.82% x 1/12)		915	912	910	907	905	902	900	897	895	892	889	887	10,811
8.	Investment Expenses														
	a. Depreciation (C)		1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	12,936
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,855	4,845	4,835	4,824	4,814	4,803	4,793	4,782	4,772	4,761	4,750	4,740	57,574
	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		4,855	4,845	4,835	4,824	4,814	4,803	4,793	4,782	4,772	4,761	4,750	4,740	57,574
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		4,693	4,684	4,674	4,663	4,654	4,643	4,633	4,623	4,613	4,602	4,592	4,582	55,656
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,693	$4,684	$4,674	$4,663	$4,654	$4,643	$4,633	$4,623	$4,613	$4,602	$4,592	$4,582	$55,656

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 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

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 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 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	(177,244)	(179,017)	(180,790)	(182,563)	(184,336)	(186,109)	(187,882)	(189,655)	(191,428)	(193,201)	(194,974)	(196,747)	(198,520)	
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)	$641,157	639,384	637,611	635,838	634,065	632,292	630,519	628,746	626,973	625,200	623,427	621,654	619,881	
6.	Average Net Investment		640,271	638,498	636,725	634,952	633,179	631,406	629,633	627,860	626,087	624,314	622,541	620,768	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,708	4,695	4,682	4,669	4,656	4,643	4,630	4,617	4,604	4,591	4,578	4,565	$55,638
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,505	1,500	1,496	1,492	1,488	1,484	1,480	1,475	1,471	1,467	1,463	1,459	17,780
8.	Investment Expenses														
	a. Depreciation (C)		1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	21,276
	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)		7,986	7,968	7,951	7,934	7,917	7,900	7,883	7,865	7,848	7,831	7,814	7,797	94,694
	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		7,986	7,968	7,951	7,934	7,917	7,900	7,883	7,865	7,848	7,831	7,814	7,797	94,694
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
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)		7,720	7,702	7,686	7,670	7,653	7,637	7,620	7,603	7,586	7,570	7,554	7,537	91,538
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,720	$7,702	$7,686	$7,670	$7,653	$7,637	$7,620	$7,603	$7,586	$7,570	$7,554	$7,537	$91,538

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 2.6%
(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 Current Period Actual / Estimated Amount
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 1 for FDEP
(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 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	(17,388)	(17,531)	(17,674)	(17,817)	(17,960)	(18,103)	(18,246)	(18,389)	(18,532)	(18,675)	(18,818)	(18,961)	(19,104)	
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)	$39,889	39,746	39,603	39,460	39,317	39,174	39,031	38,888	38,745	38,602	38,459	38,316	38,173	
6.	Average Net Investment		39,818	39,675	39,532	39,389	39,246	39,103	38,960	38,817	38,674	38,531	38,388	38,245	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		293	292	291	290	289	288	286	285	284	283	282	281	$3,444
	b. Debt Component (Line 6 x 2.82% x 1/12)		94	93	93	93	92	92	92	91	91	91	90	90	1,102
8.	Investment Expenses														
	a. Depreciation (C)		143	143	143	143	143	143	143	143	143	143	143	143	1,716
	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)		530	528	527	526	524	523	521	519	518	517	515	514	6,262
	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		530	528	527	526	524	523	521	519	518	517	515	514	6,262
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
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)		512	510	509	508	507	506	504	502	501	500	498	497	6,054
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$512	$510	$509	$508	$507	$506	$504	$502	$501	$500	$498	$497	$6,054

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 3.0%
(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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 4 for FDEP
(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 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	(27,875)	(28,101)	(28,327)	(28,553)	(28,779)	(29,005)	(29,231)	(29,457)	(29,683)	(29,909)	(30,135)	(30,361)	(30,587)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$62,597	62,371	62,145	61,919	61,693	61,467	61,241	61,015	60,789	60,563	60,337	60,111	59,885	
6.	Average Net Investment		62,484	62,258	62,032	61,806	61,580	61,354	61,128	60,902	60,676	60,450	60,224	59,998	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		459	458	456	454	453	451	449	448	446	444	443	441	$5,402
	b. Debt Component (Line 6 x 2.82% x 1/12)		147	146	146	145	145	144	144	143	143	142	142	141	1,728
8.	Investment Expenses														
	a. Depreciation (C)		226	226	226	226	226	226	226	226	226	226	226	226	2,712
	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)		832	830	828	825	824	821	819	817	815	812	811	808	9,842
	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		832	830	828	825	824	821	819	817	815	812	811	808	9,842
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
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)		804	802	800	798	797	794	792	790	788	785	784	781	9,515
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$804	$802	$800	$798	$797	$794	$792	$790	$788	$785	$784	$781	$9,515

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 3.0%
(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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(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 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	(388,712)	(392,332)	(395,952)	(399,572)	(403,192)	(406,812)	(410,432)	(414,052)	(417,672)	(421,292)	(424,912)	(428,532)	(432,152)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$927,545	923,925	920,305	916,685	913,065	909,445	905,825	902,205	898,585	894,965	891,345	887,725	884,105	
6.	Average Net Investment		925,735	922,115	918,495	914,875	911,255	907,635	904,015	900,395	896,775	893,155	889,535	885,915	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		6,807	6,780	6,754	6,727	6,701	6,674	6,647	6,621	6,594	6,568	6,541	6,514	$79,928
	b. Debt Component (Line 6 x 2.82% x 1/12)		2,175	2,167	2,158	2,150	2,141	2,133	2,124	2,116	2,107	2,099	2,090	2,082	25,542
8.	Investment Expenses														
	a. Depreciation (C)		3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	43,440
	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)		12,602	12,567	12,532	12,497	12,462	12,427	12,391	12,357	12,321	12,287	12,251	12,216	148,910
	a. Recoverable Costs Allocated to Energy		12,602	12,567	12,532	12,497	12,462	12,427	12,391	12,357	12,321	12,287	12,251	12,216	148,910
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		12,288	12,056	12,155	11,951	11,982	12,008	11,901	11,808	11,813	11,741	11,875	11,802	143,380
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$12,288	$12,056	$12,155	$11,951	$11,982	$12,008	$11,901	$11,808	$11,813	$11,741	$11,875	$11,802	$143,380

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 3.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(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 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	(307,638)	(310,182)	(312,726)	(315,270)	(317,814)	(320,358)	(322,902)	(325,446)	(327,990)	(330,534)	(333,078)	(335,622)	(338,166)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$677,156	674,612	672,068	669,524	666,980	664,436	661,892	659,348	656,804	654,260	651,716	649,172	646,628	
6.	Average Net Investment		675,884	673,340	670,796	668,252	665,708	663,164	660,620	658,076	655,532	652,988	650,444	647,900	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,970	4,951	4,932	4,914	4,895	4,876	4,858	4,839	4,820	4,802	4,783	4,764	$58,404
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,588	1,582	1,576	1,570	1,564	1,558	1,552	1,546	1,541	1,535	1,529	1,523	18,664
8.	Investment Expenses														
	a. Depreciation (C)		2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	30,528
	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)		9,102	9,077	9,052	9,028	9,003	8,978	8,954	8,929	8,905	8,881	8,856	8,831	107,596
	a. Recoverable Costs Allocated to Energy		9,102	9,077	9,052	9,028	9,003	8,978	8,954	8,929	8,905	8,881	8,856	8,831	107,596
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		8,876	8,708	8,779	8,634	8,656	8,675	8,600	8,532	8,538	8,486	8,584	8,531	103,599
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)		$8,876	$8,708	$8,779	$8,634	$8,656	$8,675	$8,600	$8,532	$8,538	$8,486	$8,584	$8,531	$103,599

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 3.1%
(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 2007 to December 2007

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 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 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	(18,823)	(19,024)	(19,225)	(19,426)	(19,627)	(19,828)	(20,029)	(20,230)	(20,431)	(20,632)	(20,833)	(21,034)	(21,235)	
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)	$101,914	101,713	101,512	101,311	101,110	100,909	100,708	100,507	100,306	100,105	99,904	99,703	99,502	
6.	Average Net Investment		101,814	101,613	101,412	101,211	101,010	100,809	100,608	100,407	100,206	100,005	99,804	99,603	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		749	747	746	744	743	741	740	738	737	735	734	732	$8,886
	b. Debt Component (Line 6 x 2.82% x 1/12)		239	239	238	238	237	237	236	236	235	235	235	234	2,839
8.	Investment Expenses														
	a. Depreciation (C)		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	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)		1,189	1,187	1,185	1,183	1,181	1,179	1,177	1,175	1,173	1,171	1,170	1,167	14,137
	a. Recoverable Costs Allocated to Energy		1,189	1,187	1,185	1,183	1,181	1,179	1,177	1,175	1,173	1,171	1,170	1,167	14,137
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		1,159	1,139	1,149	1,131	1,136	1,139	1,130	1,123	1,125	1,119	1,134	1,127	13,611
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)		$1,159	$1,139	$1,149	$1,131	$1,136	$1,139	$1,130	$1,123	$1,125	$1,119	$1,134	$1,127	$13,611

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 2.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

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 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 Total
1.	Investments														
	a. Expenditures/Additions		$1,359	$0	$0	$0	$0	$0	$0	$0	$1,275	$5,000	$7,222	$3,503	$18,359
	b. Clearings to Plant		234,039	0	0	0	0	0	0	0	0	0	0	0	234,039
	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)	$83,318,932	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	
3.	Less: Accumulated Depreciation	(24,498,151)	(24,699,729)	(24,901,532)	(25,103,335)	(25,305,138)	(25,506,941)	(25,708,744)	(25,910,547)	(26,112,350)	(26,314,153)	(26,515,956)	(26,717,759)	(26,919,562)	
4.	CWIP - Non-Interest Bearing	232,670	0	0	0	0	0	0	0	0	1,275	6,275	13,497	17,000	
5.	Net Investment (Lines 2 + 3 + 4)	$59,053,451	58,853,232	58,651,429	58,449,626	58,247,823	58,046,020	57,844,217	57,642,414	57,440,611	57,240,083	57,043,280	56,848,699	56,650,399	
6.	Average Net Investment		58,953,341	58,752,330	58,550,527	58,348,724	58,146,921	57,945,118	57,743,315	57,541,512	57,340,347	57,141,681	56,945,989	56,749,549	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		433,494	432,016	430,532	429,048	427,564	426,080	424,596	423,112	421,633	420,172	418,733	417,289	$5,104,269
	b. Debt Component (Line 6 x 2.82% x 1/12)		138,540	138,068	137,594	137,120	136,645	136,171	135,697	135,223	134,750	134,283	133,823	133,361	1,631,275
8.	Investment Expenses														
	a. Depreciation (C)		201,578	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	2,421,411
	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)		773,612	771,887	769,929	767,971	766,012	764,054	762,096	760,138	758,186	756,258	754,359	752,453	9,156,955
	a. Recoverable Costs Allocated to Energy		773,612	771,887	769,929	767,971	766,012	764,054	762,096	760,138	758,186	756,258	754,359	752,453	9,156,955
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		754,365	740,500	746,743	734,426	736,509	738,267	731,948	726,372	726,929	722,659	731,176	726,929	8,816,823
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)		$754,365	$740,500	$746,743	$734,426	$736,509	$738,267	$731,948	$726,372	$726,929	$722,659	$731,176	$726,929	$8,816,823

Notes:

(A) Applicable depreciable base for Big Bend; account 312.46 ($83,318,932) and 312.45 ($234,029)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rates are 2.9% and 2.3%.
(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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(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 Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	
3.	Less: Accumulated Depreciation	(3,032,677)	(3,074,319)	(3,115,961)	(3,157,603)	(3,199,245)	(3,240,887)	(3,282,529)	(3,324,171)	(3,365,813)	(3,407,455)	(3,449,097)	(3,490,739)	(3,532,381)	
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)	$18,707,060	18,665,418	18,623,776	18,582,134	18,540,492	18,498,850	18,457,208	18,415,566	18,373,924	18,332,282	18,290,640	18,248,998	18,207,356	
6.	Average Net Investment		18,686,239	18,644,597	18,602,955	18,561,313	18,519,671	18,478,029	18,436,387	18,394,745	18,353,103	18,311,461	18,269,819	18,228,177	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		137,403	137,097	136,791	136,484	136,178	135,872	135,566	135,260	134,953	134,647	134,341	134,035	$1,628,627
	b. Debt Component (Line 6 x 2.82% x 1/12)		43,913	43,815	43,717	43,619	43,521	43,423	43,326	43,228	43,130	43,032	42,934	42,836	520,494
8.	Investment Expenses														
	a. Depreciation (C)		41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	499,704
	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)		222,958	222,554	222,150	221,745	221,341	220,937	220,534	220,130	219,725	219,321	218,917	218,513	2,648,825
	a. Recoverable Costs Allocated to Energy		222,958	222,554	222,150	221,745	221,341	220,937	220,534	220,130	219,725	219,321	218,917	218,513	2,648,825
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		217,411	213,504	215,460	212,059	212,816	213,480	211,810	210,352	210,667	209,577	212,189	211,101	2,550,426
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)		$217,411	$213,504	$215,460	$212,059	$212,816	$213,480	$211,810	$210,352	$210,667	$209,577	$212,189	$211,101	$2,550,426

Notes:

(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45 ($21,699,919)
(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 1.5% and 2.3%
(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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(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 Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,000	$50,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	
3.	Less: Accumulated Depreciation	(231,803)	(247,730)	(263,657)	(279,584)	(295,511)	(311,438)	(327,365)	(343,292)	(359,219)	(375,146)	(391,073)	(407,000)	(422,927)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	50,000	
5.	Net Investment (Lines 2 + 3 + 4)	$5,896,407	5,880,480	5,864,553	5,848,626	5,832,699	5,816,772	5,800,845	5,784,918	5,768,991	5,753,064	5,737,137	5,721,210	5,755,283	
6.	Average Net Investment		5,888,444	5,872,517	5,856,590	5,840,663	5,824,736	5,808,809	5,792,882	5,776,955	5,761,028	5,745,101	5,729,174	5,738,247	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		43,299	43,182	43,064	42,947	42,830	42,713	42,596	42,479	42,362	42,245	42,128	42,194	$512,039
	b. Debt Component (Line 6 x 2.82% x 1/12)		13,838	13,800	13,763	13,726	13,688	13,651	13,613	13,576	13,538	13,501	13,464	13,485	163,643
8.	Investment Expenses														
	a. Depreciation (C)		15,927	15,927	15,927	15,927	15,927	15,927	15,927	15,927	15,927	15,927	15,927	15,927	191,124
	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)		73,064	72,909	72,754	72,600	72,445	72,291	72,136	71,982	71,827	71,673	71,519	71,606	866,806
	a. Recoverable Costs Allocated to Energy		73,064	72,909	72,754	72,600	72,445	72,291	72,136	71,982	71,827	71,673	71,519	71,606	866,806
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		71,246	69,944	70,563	69,429	69,655	69,851	69,282	68,785	68,866	68,489	69,321	69,177	834,608
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)		$71,246	$69,944	$70,563	$69,429	$69,655	$69,851	$69,282	$68,785	$68,866	$68,489	$69,321	$69,177	$834,608

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($4,013,075), and 312.43 ($439,964)
(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 3.3%, 3.1%, and 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

DOCKET NO. 070007-EI
ECRC 2007 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(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 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)	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	
3.	Less: Accumulated Depreciation	(483,639)	(503,834)	(524,029)	(544,224)	(564,419)	(584,614)	(604,809)	(625,004)	(645,199)	(665,394)	(685,589)	(705,784)	(725,979)	
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)	$7,507,413	7,487,218	7,467,023	7,446,828	7,426,633	7,406,438	7,386,243	7,366,048	7,345,853	7,325,658	7,305,463	7,285,268	7,265,073	
6.	Average Net Investment		7,497,316	7,477,121	7,456,926	7,436,731	7,416,536	7,396,341	7,376,146	7,355,951	7,335,756	7,315,561	7,295,366	7,275,171	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		55,129	54,981	54,832	54,684	54,535	54,387	54,238	54,090	53,941	53,793	53,644	53,496	$651,750
	b. Debt Component (Line 6 x 2.82% x 1/12)		17,619	17,571	17,524	17,476	17,429	17,381	17,334	17,286	17,239	17,192	17,144	17,097	208,292
8.	Investment Expenses														
	a. Depreciation (C)		20,195	20,195	20,195	20,195	20,195	20,195	20,195	20,195	20,195	20,195	20,195	20,195	242,340
	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)		92,943	92,747	92,551	92,355	92,159	91,963	91,767	91,571	91,375	91,180	90,983	90,788	1,102,382
	a. Recoverable Costs Allocated to Energy		92,943	92,747	92,551	92,355	92,159	91,963	91,767	91,571	91,375	91,180	90,983	90,788	1,102,382
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		90,631	88,976	89,764	88,321	88,609	88,859	88,137	87,503	87,608	87,129	88,187	87,708	1,061,432
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)		$90,631	$88,976	$89,764	$88,321	$88,609	$88,859	$88,137	$87,503	$87,608	$87,129	$88,187	$87,708	$1,061,432

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,513,263), 312.42 ($5,153,072), 312.43 ($955,619), 315.41 ($17,504), and 315.44 ($351,594)
(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 3.3%, 3.1%, 2.6%, 2.5%, and 2.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(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 Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(152,442)	(156,866)	(161,290)	(165,714)	(170,138)	(174,562)	(178,986)	(183,410)	(187,834)	(192,258)	(196,682)	(201,106)	(205,530)	
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)	$1,409,031	1,404,607	1,400,183	1,395,759	1,391,335	1,386,911	1,382,487	1,378,063	1,373,639	1,369,215	1,364,791	1,360,367	1,355,943	
6.	Average Net Investment		1,406,819	1,402,395	1,397,971	1,393,547	1,389,123	1,384,699	1,380,275	1,375,851	1,371,427	1,367,003	1,362,579	1,358,155	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,345	10,312	10,280	10,247	10,214	10,182	10,149	10,117	10,084	10,052	10,019	9,987	$121,988
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,306	3,296	3,285	3,275	3,264	3,254	3,244	3,233	3,223	3,212	3,202	3,192	38,986
8.	Investment Expenses														
	a. Depreciation (C)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,075	18,032	17,989	17,946	17,902	17,860	17,817	17,774	17,731	17,688	17,645	17,603	214,062
	a. Recoverable Costs Allocated to Energy		18,075	18,032	17,989	17,946	17,902	17,860	17,817	17,774	17,731	17,688	17,645	17,603	214,062
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		17,625	17,299	17,447	17,162	17,212	17,257	17,112	16,984	17,000	16,902	17,103	17,006	206,109
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)		$17,625	$17,299	$17,447	$17,162	$17,212	$17,257	$17,112	$16,984	$17,000	$16,902	$17,103	$17,006	$206,109

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

DOCKET NO. 070007-EI
ECRC 2007 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(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 Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(141,830)	(146,947)	(152,064)	(157,181)	(162,298)	(167,415)	(172,532)	(177,649)	(182,766)	(187,883)	(193,000)	(198,117)	(203,234)	
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)	$2,416,900	2,411,783	2,406,666	2,401,549	2,396,432	2,391,315	2,386,198	2,381,081	2,375,964	2,370,847	2,365,730	2,360,613	2,355,496	
6.	Average Net Investment		2,414,342	2,409,225	2,404,108	2,398,991	2,393,874	2,388,757	2,383,640	2,378,523	2,373,406	2,368,289	2,363,172	2,358,055	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		17,753	17,715	17,678	17,640	17,603	17,565	17,527	17,490	17,452	17,414	17,377	17,339	$210,553
	b. Debt Component (Line 6 x 2.82% x 1/12)		5,674	5,662	5,650	5,638	5,626	5,614	5,602	5,590	5,578	5,565	5,553	5,541	67,293
8.	Investment Expenses														
	a. Depreciation (C)		5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	61,404
	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)		28,544	28,494	28,445	28,395	28,346	28,296	28,246	28,197	28,147	28,096	28,047	27,997	339,250
	a. Recoverable Costs Allocated to Energy		28,544	28,494	28,445	28,395	28,346	28,296	28,246	28,197	28,147	28,096	28,047	27,997	339,250
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		27,834	27,335	27,588	27,155	27,254	27,341	27,129	26,944	26,987	26,848	27,185	27,047	326,647
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)		$27,834	$27,335	$27,588	$27,155	$27,254	$27,341	$27,129	$26,944	$26,987	$26,848	$27,185	$27,047	$326,647

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 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(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 Total
1.	Investments														
	a. Expenditures/Additions		$433	($3,744)	$630	$369	$362	$356	$0	$0	$0	$0	$0	$0	($1,594)
	b. Clearings to Plant		1,653,621	(4,500)	0	0	0	0	0	0	0	0	0	0	1,649,121
	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	$1,653,621	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	0	(2,274)	(6,815)	(11,350)	(15,885)	(20,420)	(24,955)	(29,490)	(34,025)	(38,560)	(43,095)	(47,630)	(52,165)	
4.	CWIP - Non-Interest Bearing	2,014,682	361,494	362,250	362,880	363,249	363,611	363,967	363,967	363,967	363,967	363,967	363,967	363,967	
5.	Net Investment (Lines 2 + 3 + 4)	$2,014,682	2,012,841	2,004,556	2,000,651	1,996,485	1,992,312	1,988,133	1,983,598	1,979,063	1,974,528	1,969,993	1,965,458	1,960,923	
6.	Average Net Investment		2,013,762	2,008,699	2,002,604	1,998,568	1,994,399	1,990,223	1,985,866	1,981,331	1,976,796	1,972,261	1,967,726	1,963,191	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		14,808	14,770	14,725	14,696	14,665	14,634	14,602	14,569	14,536	14,502	14,469	14,436	$175,412
	b. Debt Component (Line 6 x 2.82% x 1/12)		4,732	4,720	4,706	4,697	4,687	4,677	4,667	4,656	4,645	4,635	4,624	4,613	56,059
8.	Investment Expenses														
	a. Depreciation (C)		2,274	4,541	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	52,165
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		21,814	24,031	23,966	23,928	23,887	23,846	23,804	23,760	23,716	23,672	23,628	23,584	283,636
	a. Recoverable Costs Allocated to Energy		21,814	24,031	23,966	23,928	23,887	23,846	23,804	23,760	23,716	23,672	23,628	23,584	283,636
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		21,271	23,054	23,244	22,883	22,967	23,041	22,862	22,705	22,738	22,620	22,902	22,784	273,071
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$21,271	$23,054	$23,244	$22,883	$22,967	$23,041	$22,862	$22,705	$22,738	$22,620	$22,902	$22,784	$273,071

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 3.3%
(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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(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 Total
1.	Investments														
	a. Expenditures/Additions		($13,317)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($13,317)
	b. Clearings to Plant		1,581,887	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	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	0	(2,043)	(6,130)	(10,217)	(14,304)	(18,391)	(22,478)	(26,565)	(30,652)	(34,739)	(38,826)	(42,913)	(47,000)	
4.	CWIP - Non-Interest Bearing	1,595,204	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,595,204	1,579,844	1,575,757	1,571,670	1,567,583	1,563,496	1,559,409	1,555,322	1,551,235	1,547,148	1,543,061	1,538,974	1,534,887	
6.	Average Net Investment		1,587,524	1,577,801	1,573,714	1,569,627	1,565,540	1,561,453	1,557,366	1,553,279	1,549,192	1,545,105	1,541,018	1,536,931	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		11,673	11,602	11,572	11,542	11,512	11,482	11,452	11,422	11,391	11,361	11,331	11,301	$137,641
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,731	3,708	3,698	3,689	3,679	3,669	3,660	3,650	3,641	3,631	3,621	3,612	43,989
8.	Investment Expenses														
	a. Depreciation (C)		2,043	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	47,000
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,447	19,397	19,357	19,318	19,278	19,238	19,199	19,159	19,119	19,079	19,039	19,000	228,630
	a. Recoverable Costs Allocated to Energy		17,447	19,397	19,357	19,318	19,278	19,238	19,199	19,159	19,119	19,079	19,039	19,000	228,630
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		17,013	18,608	18,774	18,474	18,535	18,589	18,439	18,308	18,331	18,231	18,454	18,356	220,112
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)		$17,013	$18,608	$18,774	$18,474	$18,535	$18,589	$18,439	$18,308	$18,331	$18,231	$18,454	$18,356	$220,112

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 3.1%
(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 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(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 Total
1.	Investments														
	a. Expenditures/Additions		$67,721	($292)	$64,850	$7,078	$0	($373)	$5,800	$389,203	$93,992	$181,652	$725,812	$298,936	$1,834,379
	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	710,718	778,439	778,147	842,997	850,075	850,075	849,702	855,502	1,244,705	1,338,697	1,520,349	2,246,161	2,545,097	
5.	Net Investment (Lines 2 + 3 + 4)	$710,718	778,439	778,147	842,997	850,075	850,075	849,702	855,502	1,244,705	1,338,697	1,520,349	2,246,161	2,545,097	
6.	Average Net Investment		744,579	778,293	810,572	846,536	850,075	849,889	852,602	1,050,104	1,291,701	1,429,523	1,883,255	2,395,629	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,475	5,723	5,960	6,225	6,251	6,249	6,269	7,722	9,498	10,512	13,848	17,615	$101,347
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,750	1,829	1,905	1,989	1,998	1,997	2,004	2,468	3,035	3,359	4,426	5,630	32,390
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)		7,225	7,552	7,865	8,214	8,249	8,246	8,273	10,190	12,533	13,871	18,274	23,245	133,737
	a. Recoverable Costs Allocated to Energy		7,225	7,552	7,865	8,214	8,249	8,246	8,273	10,190	12,533	13,871	18,274	23,245	133,737
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		7,045	7,245	7,628	7,855	7,931	7,968	7,946	9,737	12,016	13,255	17,712	22,457	128,795
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)		$7,045	$7,245	$7,628	$7,855	$7,931	$7,968	$7,946	$9,737	$12,016	$13,255	$17,712	$22,457	$128,795

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 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 Current Period Actual / Estimated Amount
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(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 Total
1.	Investments														
	a. Expenditures/Additions		$1,189,709	$1,394,762	$1,841,932	$903,592	$1,304,902	$1,041,502	$3,346,037	$1,335,317	$2,001,723	$2,288,063	$2,257,895	$1,835,244	$20,740,678
	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)	$7,504,877	$8,694,586	$10,089,348	$11,931,280	$12,834,872	$14,139,774	$15,181,276	$18,527,313	$19,862,630	$21,864,353	$24,152,416	$26,410,311	$28,245,555	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,504,877	8,694,586	10,089,348	11,931,280	12,834,872	14,139,774	15,181,276	18,527,313	19,862,630	21,864,353	24,152,416	26,410,311	28,245,555	
6.	Average Net Investment		8,099,732	9,391,967	11,010,314	12,383,076	13,487,323	14,660,525	16,854,295	19,194,972	20,863,492	23,008,385	25,281,364	27,327,933	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41 and 315.41. These dollars are for tracking purposes only; depreciation and return are not calculated until the project goes in to service.
(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% and 2.5%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(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 Total
1.	Investments														
	a. Expenditures/Additions		$2,169,237	$1,966,611	$1,549,258	$826,974	$3,161,956	$1,416,687	$3,715,146	$1,985,938	$2,259,519	$2,999,939	$2,591,952	$2,933,581	$27,576,798
	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)	$7,634,814	$9,804,051	$11,770,662	$13,319,920	$14,146,894	$17,308,850	$18,725,537	$22,440,683	$24,426,621	$26,686,140	$29,686,079	$32,278,031	$35,211,612	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,634,814	9,804,051	11,770,662	13,319,920	14,146,894	17,308,850	18,725,537	22,440,683	24,426,621	26,686,140	29,686,079	32,278,031	35,211,612	
6.	Average Net Investment		8,719,433	10,787,357	12,545,291	13,733,407	15,727,872	18,017,194	20,583,110	23,433,652	25,556,381	28,186,110	30,982,055	33,744,822	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41 and 315.41. These dollars are for tracking purposes only; depreciation and return are not calculated until the project goes in to service.
(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 are 3.3% and 2.5%.
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(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 Total
1.	Investments														
	a. Expenditures/Additions		$5,543,583	$3,739,520	$1,899,292	$3,622,534	$3,376,444	$3,027,856	$2,540,395	$2,105,317	$1,999,609	$2,191,410	$4,165,630	$3,335,257	$37,546,847
	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)	$28,867,509	$34,411,092	$38,150,612	$40,049,904	$43,672,438	$47,048,882	$50,076,738	$52,617,133	$54,722,450	$56,722,059	$58,913,469	$63,079,099	$66,414,356	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$28,867,509	34,411,092	38,150,612	40,049,904	43,672,438	47,048,882	50,076,738	52,617,133	54,722,450	56,722,059	58,913,469	63,079,099	66,414,356	
6.	Average Net Investment		31,639,301	36,280,852	39,100,258	41,861,171	45,360,660	48,562,810	51,346,936	53,669,792	55,722,255	57,817,764	60,996,284	64,746,728	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41 and 315.41. These dollars are for tracking purposes only; depreciation and return are not calculated until the project goes in to service.
(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 are 3.3% and 2.5%.
(D) Line 9a x Line 10
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

DOCKET NO. 070007-EI
ECRC 2007 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(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 Total
1.	Investments														
	a. Expenditures/Additions		$1,001,114	$1,240,693	$2,246,817	$274,912	$843,768	$740,518	$310,081	$130,425	$310,256	$211,802	$0	$165,427	$7,475,813
	b. Clearings to Plant		0	0	0	0	59,973,427	719,053	250,081	70,425	250,256	148,291	319,695	165,427	61,896,655
	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)	$51,686,174	$52,687,288	$53,927,981	$56,174,798	$56,449,710	$59,973,427	$60,692,480	$60,942,561	$61,012,986	$61,263,242	$61,411,533	$61,731,228	$61,896,655	
3.	Less: Accumulated Depreciation	0	0	0	0	0	(59,973)	(180,639)	(302,274)	(424,230)	(546,506)	(669,181)	(792,324)	(915,952)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$51,686,174	52,687,288	53,927,981	56,174,798	56,449,710	59,913,454	60,511,841	60,640,287	60,588,756	60,716,736	60,742,352	60,938,904	60,980,703	
6.	Average Net Investment		52,186,731	53,307,635	55,051,390	56,312,254	58,181,582	60,212,648	60,576,064	60,614,522	60,652,746	60,729,544	60,840,628	60,959,804	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	82,804	442,754	445,426	445,709	445,990	446,554	447,371	448,248	$3,204,856
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	26,463	141,500	142,354	142,444	142,534	142,714	142,975	143,256	1,024,240
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	59,973	120,666	121,635	121,956	122,276	122,675	123,143	123,628	915,952
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	169,240	704,920	709,415	710,109	710,800	711,943	713,489	715,132	5,145,048
	a. Recoverable Costs Allocated to Energy		0	0	0	0	169,240	704,920	709,415	710,109	710,800	711,943	713,489	715,132	5,145,048
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	162,722	681,129	681,351	678,565	681,496	680,312	691,562	690,874	4,948,011
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$162,722	$681,129	$681,351	$678,565	$681,496	$680,312	$691,562	$690,874	$4,948,011

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 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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ECRC 2007 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(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 Total
1.	Investments														
	a. Expenditures/Additions		$174,114	$1,348,917	$2,219,239	$351,809	$600,111	$161,088	$277,779	$265,574	$225,675	$396,175	$673,776	$1,296,648	$7,990,905
	b. Clearings to Plant		0	0	0	0	4,815,699	30,093	81,050	81,060	0	0	0	0	5,007,902
	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	$4,815,699	$4,845,792	$4,926,842	$5,007,902	$5,007,902	$5,007,902	$5,007,902	$5,007,902	
3.	Less: Accumulated Depreciation	0	0	0	0	0	(4,615)	(13,874)	(23,239)	(32,760)	(42,358)	(51,956)	(61,554)	(71,152)	
4.	CWIP - Non-Interest Bearing	1,770,578	1,944,692	3,293,609	5,512,848	5,864,657	1,649,069	1,780,064	1,976,793	2,161,307	2,386,982	2,783,157	3,456,933	4,753,581	
5.	Net Investment (Lines 2 + 3 + 4)	$1,770,578	1,944,692	3,293,609	5,512,848	5,864,657	6,460,153	6,611,982	6,880,396	7,136,449	7,352,526	7,739,103	8,403,281	9,690,331	
6.	Average Net Investment		1,857,635	2,619,151	4,403,229	5,688,753	6,162,405	6,536,068	6,746,189	7,008,423	7,244,488	7,545,815	8,071,192	9,046,806	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		13,659	19,259	32,378	41,830	45,313	48,061	49,606	51,534	53,270	55,486	59,349	66,523	$536,268
	b. Debt Component (Line 6 x 2.82% x 1/12)		4,365	6,155	10,348	13,369	14,482	15,360	15,854	16,470	17,025	17,733	18,967	21,260	171,388
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	4,615	9,259	9,365	9,521	9,598	9,598	9,598	9,598	71,152
	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)		18,024	25,414	42,726	55,199	64,410	72,680	74,825	77,525	79,893	82,817	87,914	97,381	778,808
	a. Recoverable Costs Allocated to Energy		18,024	25,414	42,726	55,199	64,410	72,680	74,825	77,525	79,893	82,817	87,914	97,381	778,808
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		17,576	24,381	41,439	52,788	61,929	70,227	71,865	74,081	76,599	79,138	85,212	94,078	749,313
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)		$17,576	$24,381	$41,439	$52,788	$61,929	$70,227	$71,865	$74,081	$76,599	$79,138	$85,212	$94,078	$749,313

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 2.3%.
(D) Line 9a x Line 10
(E) Line 9b x Line 11

DOCKET NO. 070007-EI
ECRC 2007 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Air Mercury Rule
(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 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	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, 345.81
(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 3.3%, 2.6%, 2.4%, 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2007 to December 2007

For Project: SO_2 Emissions 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 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	1,035,500	11,622,780	4,071,250	6,807,500	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	78,537,030
	c. Auction Proceeds/Other		0	0	0	0	773,503	0	0	0	0	0	0	0	773,503
2.	Working Capital Balance														
	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 254.01 Regulatory Liabilities - Gains	(832,866)	(782,420)	(778,445)	(775,323)	(763,581)	(666,714)	(633,561)	(587,500)	(495,352)	(403,472)	(312,015)	(221,053)	(130,952)	
3.	Total Working Capital Balance	($832,866)	(782,420)	(778,445)	(775,323)	(763,581)	(666,714)	(633,561)	(587,500)	(495,352)	(403,472)	(312,015)	(221,053)	(130,952)	
4.	Average Net Working Capital Balance		($807,643)	($780,433)	($776,884)	($769,452)	($715,148)	($650,138)	($610,531)	($541,426)	($449,412)	($357,743)	($266,534)	($176,002)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(5,939)	(5,739)	(5,713)	(5,658)	(5,259)	(4,781)	(4,489)	(3,981)	(3,305)	(2,631)	(1,960)	(1,294)	(50,749)
	b. Debt Component (Line 4 x 2.82% x 1/12)		(1,898)	(1,834)	(1,826)	(1,808)	(1,681)	(1,528)	(1,435)	(1,272)	(1,056)	(841)	(626)	(414)	(16,219)
6.	Total Return Component		(7,837)	(7,573)	(7,539)	(7,466)	(6,940)	(6,309)	(5,924)	(5,253)	(4,361)	(3,472)	(2,586)	(1,708)	(66,968)
7.	Expenses:														
	a. Gains		0	0	0	(1,045,095)	(12,490,851)	(4,100,035)	(6,845,900)	(11,084,480)	(11,084,480)	(11,084,480)	(11,084,480)	(11,084,260)	(79,904,061)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		(25,909)	13,730	15,874	16,960	20,773	22,565	40,139	40,132	38,800	40,823	37,718	39,859	301,464
8.	Net Expenses (B)		(25,909)	13,730	15,874	(1,028,135)	(12,470,078)	(4,077,470)	(6,805,761)	(11,044,348)	(11,045,680)	(11,043,657)	(11,046,762)	(11,044,401)	(79,602,597)
9.	Total System Recoverable Expenses (Lines 6 + 8)		(33,746)	6,157	8,335	(1,035,601)	(12,477,018)	(4,083,779)	(6,811,685)	(11,049,601)	(11,050,041)	(11,047,129)	(11,049,348)	(11,046,109)	(79,669,565)
	a. Recoverable Costs Allocated to Energy		(33,746)	6,157	8,335	(1,035,601)	(12,477,018)	(4,083,779)	(6,811,685)	(11,049,601)	(11,050,041)	(11,047,129)	(11,049,348)	(11,046,109)	(79,669,565)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9751201	0.9593379	0.9698850	0.9563200	0.9614843	0.9662495	0.9604406	0.9555793	0.9587736	0.9555715	0.9692686	0.9660796	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (C)		(32,906)	5,907	8,084	(990,366)	(11,996,457)	(3,945,949)	(6,542,219)	(10,558,770)	(10,594,488)	(10,556,322)	(10,709,786)	(10,671,421)	(76,584,693)
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)		($32,906)	$5,907	$8,084	($990,366)	($11,996,457)	($3,945,949)	($6,542,219)	($10,558,770)	($10,594,488)	($10,556,322)	($10,709,786)	($10,671,421)	($76,584,693)

Notes:
(A) Line 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 6 is reported on Schedule 6E and 7E
(C) Line 8 is reported on Schedule 4E and 5E
(D) Line 9a x Line 10
(E) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

DOCKET NO. 070007-EI
ECRC 2007 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT 8, PAGE 26 OF 26

ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2008 THROUGH DECEMBER 2008

42-1P THROUGH 42-7P

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070007-EI EXHIBIT 45
COMPANY Tampa Electric Co.
WITNESS Howard T. Bryant (HTB-3)
DATE 11-06-07

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ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2008 THROUGH DECEMBER 2008

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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 2008 to December 2008

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)	($13,694,662)	$281,785	($13,412,877)
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	32,165,710	158,410	32,324,120
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	18,471,048	440,195	18,911,243
2. True-up for Estimated Over/(Under) Recovery for the current period January 2007 to December 2007 (Form 42-2E, Line 5 + 6 + 10)	9,771,819	(147,646)	9,624,173
3. Final True-up for the period January 2006 to December 2006 (Form 42-1A, Line 3)	(12,664,435)	768,752	(11,895,683)
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2008 to December 2008 (Line 1 - Line 2- Line 3)	21,363,664	(180,911)	21,182,753
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$21,379,046	($181,041)	$21,198,005

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.

DOCKET NO. 070007-EI
ECRC 2008 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 to December 2008

Form 42 - 2P

O&M Activities
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$368,500	$367,900	$265,100	$296,800	$303,600	$306,200	$306,800	$312,900	$289,000	$306,600	$312,200	$253,300	$3,688,900		$3,688,900
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	(2,450,836)	(2,456,022)	(2,450,789)	(2,451,153)	(2,449,434)	(2,451,292)	(2,449,480)	(2,449,505)	(2,451,230)	(2,449,417)	(2,453,206)	(2,451,066)	(29,413,430)		(29,413,430)
	d. Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	515,800	512,600	482,000	532,600	543,100	546,500	547,800	577,800	592,900	578,400	563,600	1,249,900	7,243,000		7,243,000
	e. Big Bend PM Minimization and Monitoring	57,900	54,200	57,900	23,400	24,100	23,400	24,100	24,100	35,400	27,400	39,800	58,300	450,000		450,000
	f. Big Bend NO_x Emissions Reduction	42,000	39,200	42,000	20,300	21,000	20,300	21,000	21,000	27,800	23,000	30,500	41,900	350,000		350,000
	g. NPDES Annual Surveillance Fees	34,500	0	0	0	0	0	0	0	0	0	0	0	34,500	34,500	
	h. Gannon Thermal Discharge Study	12,500	12,500	12,500	12,500	0	0	0	0	0	0	0	0	50,000	50,000	
	i. Polk NO_x Reduction	5,000	5,000	6,000	7,000	5,000	5,000	5,000	5,000	5,000	5,000	7,000	5,000	65,000		65,000
	j. Bayside SCR and Ammonia	5,833	5,833	5,833	5,833	5,833	5,833	5,833	5,833	5,833	5,833	5,833	5,837	70,000		70,000
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	50,000	0	50,000		50,000
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	58,900	16,100	0	0	75,000		75,000
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	2,400	72,600	75,000		75,000
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	o. Clean Water Act Section 316(b) Phase II Study	12,500	112,500	12,500	12,500	0	0	0	0	0	0	0	0	150,000	150,000	
	p. Arsenic Groundwater Standard Program	0	0	27,000	0	0	15,000	0	0	15,000	0	0	0	57,000	57,000	
	q. Big Bend 4 SCR	151,700	145,700	152,300	120,180	133,600	131,300	135,220	135,560	128,360	133,600	114,460	128,020	1,610,000		1,610,000
	r. Big Bend 3 SCR	0	0	0	157,420	182,600	179,700	185,180	185,740	180,040	183,900	163,840	188,480	1,606,900		1,606,900
2.	Total of O&M Activities	(1,244,603)	(1,200,589)	(1,387,656)	(1,262,620)	(1,230,601)	(1,218,059)	(1,218,547)	(1,181,572)	(1,112,997)	(1,169,584)	(1,163,573)	(447,729)	(13,838,130)	$291,500	($14,129,630)
3.	Recoverable Costs Allocated to Energy	(1,304,103)	(1,325,589)	(1,439,656)	(1,287,620)	(1,230,601)	(1,233,059)	(1,218,547)	(1,181,572)	(1,127,997)	(1,169,584)	(1,163,573)	(447,729)	(14,129,630)		
4.	Recoverable Costs Allocated to Demand	59,500	125,000	52,000	25,000	0	15,000	0	0	15,000	0	0	0	291,500		
5.	Retail Energy Jurisdictional Factor	0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401			
6.	Retail Demand Jurisdictional Factor	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743			
7.	Jurisdictional Energy Recoverable Costs (A)	(1,263,158)	(1,282,852)	(1,394,300)	(1,245,780)	(1,193,039)	(1,196,271)	(1,182,509)	(1,143,064)	(1,092,549)	(1,132,859)	(1,130,697)	(437,584)	(13,694,662)		
8.	Jurisdictional Demand Recoverable Costs (B)	57,517	120,834	50,267	24,167	0	14,500	0	0	14,500	0	0	0	281,785		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	($1,205,641)	($1,162,018)	($1,344,033)	($1,221,613)	($1,193,039)	($1,181,771)	($1,182,509)	($1,143,064)	($1,078,049)	($1,132,859)	($1,130,697)	($437,584)	($13,412,877)		

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

DOCKET NO. 070007-EI
ECRC 2008 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 2

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 to December 2008

Form 42-3P

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line	Description (A)	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1. a.	Big Bend Unit 3 Flue Gas Desulfunzation Integration	$68,185	$68,032	$67,879	$67,725	$67,572	$67,419	$67,266	$67,113	$66,959	$66,806	$66,653	$66,500	$808,109		$808,109
b.	Big Bend Units 1 and 2 Flue Gas Conditioning	39,001	38,872	38,741	38,611	38,481	38,351	38,221	38,091	37,960	37,831	37,700	37,571	459,431		459,431
c.	Big Bend Unit 4 Continuous Emissions Monitors	6,973	6,958	6,943	6,929	6,914	6,900	6,884	6,870	6,855	6,841	6,826	6,811	82,704		82,704
d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,729	4,719	4,709	4,699	4,688	4,678	4,667	4,657	4,646	4,636	4,625	4,615	56,068	$ 56,068	
e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,780	7,762	7,744	7,727	7,710	7,693	7,676	7,658	7,641	7,624	7,607	7,590	92,212	92,212	
f.	Phillips Upgrade Tank # 1 for FDEP	513	511	510	509	507	506	505	503	502	501	499	498	6,064	6,064	
g.	Phillips Upgrade Tank # 4 for FDEP	806	804	801	800	797	795	793	791	788	787	784	782	9,528	9,528	
h.	Big Bend Unit 1 Classifier Replacement	12,181	12,146	12,110	12,076	12,040	12,006	11,970	11,935	11,900	11,865	11,829	11,795	143,853		143,853
i.	Big Bend Unit 2 Classifier Replacement	8,806	8,782	8,757	8,732	8,708	8,683	8,658	8,633	8,609	8,584	8,559	8,535	104,046		104,046
j.	Big Bend Section 114 Mercury Testing Platform	1,166	1,163	1,162	1,159	1,158	1,156	1,154	1,152	1,150	1,148	1,146	1,144	13,858		13,858
k.	Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	750,512	748,554	746,596	744,638	742,679	740,721	738,764	736,806	737,211	739,978	742,790	745,844	8,915,093		8,915,093
l.	Big Bend FGD Optimization and Utilization	218,109	217,704	217,301	216,897	216,493	216,089	215,684	215,280	214,876	214,473	214,069	213,664	2,590,639		2,590,639
m.	Big Bend NO_x Emissions Reduction	71,694	71,540	71,385	71,231	71,464	72,086	72,708	73,677	74,304	74,239	74,201	74,185	872,714		872,714
n.	Big Bend PM Minimization and Monitoring	90,955	91,608	92,503	93,521	94,666	95,348	95,290	95,084	94,877	94,671	94,465	94,259	1,127,247		1,127,247
o.	Polk NO_x Emissions Reduction	17,559	17,517	17,473	17,431	17,388	17,345	17,302	17,258	17,216	17,173	17,130	17,087	207,879		207,879
p.	Big Bend Unit 4 SOFA	27,948	27,898	27,848	27,799	27,749	27,699	27,650	27,600	27,551	27,501	27,451	27,402	332,096		332,096
q.	Big Bend Unit 1 Pre-SCR	23,562	23,518	23,453	23,408	23,364	23,321	23,276	23,232	23,189	23,144	23,100	23,057	279,624		279,624
r.	Big Bend Unit 2 Pre-SCR	18,960	18,921	18,881	18,841	18,802	18,762	18,723	18,683	18,643	18,604	18,564	18,525	224,909		224,909
s.	Big Bend Unit 3 Pre-SCR	25,249	26,542	28,829	34,853	39,744	40,350	40,503	40,432	40,360	40,288	40,217	40,145	437,512		437,512
t.	Big Bend Unit 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
u.	Big Bend Unit 2 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
v.	Big Bend Unit 3 SCR	0	0	0	837,308	961,199	975,550	984,155	991,344	997,570	1,003,842	1,010,161	1,017,407	8,778,536		8,778,536
w.	Big Bend Unit 4 SCR	238,200	237,968	237,736	237,503	237,271	708,893	707,692	706,490	705,289	704,088	702,886	701,685	6,125,701		6,125,701
x.	Big Bend FGD System Reliability	105,036	108,310	112,492	122,835	131,941	133,535	134,039	134,024	135,948	139,814	143,679	147,546	1,549,199		1,549,199
y.	Clean Air Mercury Rule	558	2,741	4,390	4,439	4,488	9,872	15,255	15,303	15,352	15,401	15,449	16,069	119,317		119,317
z.	SO_2 Emissions Allowances (B)	(1,230)	(1,149)	(1,069)	(984)	(897)	(810)	(723)	(635)	(547)	(460)	(373)	(288)	(9,165)		(9,165)
2.	Total Investment Projects - Recoverable Costs	1,737,252	1,741,421	1,747,174	2,598,687	2,734,926	3,226,948	3,238,112	3,241,981	3,248,849	3,259,379	3,270,017	3,282,428	33,327,174	$ 163,872	$ 33,163,302
3.	Recoverable Costs Allocated to Energy	1,723,424	1,727,625	1,733,410	2,584,952	2,721,224	3,213,276	3,224,471	3,228,372	3,235,272	3,245,831	3,256,502	3,268,943	33,163,302		
4.	Recoverable Costs Allocated to Demand	13,828	13,796	13,764	13,735	13,702	13,672	13,641	13,609	13,577	13,548	13,515	13,485	163,872		
5.	Retail Energy Jurisdictional Factor	0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401			
6.	Retail Demand Jurisdictional Factor	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743			
7.	Jurisdictional Energy Recoverable Costs (C)	1,669,314	1,671,926	1,678,800	2,500,957	2,638,162	3,117,408	3,129,109	3,123,159	3,133,602	3,143,911	3,164,493	3,194,869	32,165,710		
8.	Jurisdictional Demand Recoverable Costs (D)	13,367	13,336	13,305	13,277	13,245	13,216	13,186	13,155	13,125	13,097	13,065	13,036	158,410		
9.	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 • 8)	$1,682,681	$1,685,262	$1,692,105	$2,514,234	$2,651,407	$3,130,624	$3,142,295	$3,136,314	$3,146,727	$3,157,008	$3,177,558	$3,207,905	$32,324,120		

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

DOCKET NO. 070007-EI
ECRC 2008 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 3

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 to December 2008

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 January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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	(2,832,261)	(2,848,054)	(2,863,847)	(2,879,640)	(2,895,433)	(2,911,226)	(2,927,019)	(2,942,812)	(2,958,605)	(2,974,398)	(2,990,191)	(3,005,984)	(3,021,777)	
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)	$5,407,397	5,391,604	5,375,811	5,360,018	5,344,225	5,328,432	5,312,639	5,296,846	5,281,053	5,265,260	5,249,467	5,233,674	5,217,881	
6.	Average Net Investment		5,399,501	5,383,708	5,367,915	5,352,122	5,336,329	5,320,536	5,304,743	5,288,950	5,273,157	5,257,364	5,241,571	5,225,778	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		39,703	39,587	39,471	39,355	39,239	39,123	39,007	38,891	38,774	38,658	38,542	38,426	$468,776
	b. Debt Component (Line 6 x 2.82% x 1/12)		12,689	12,652	12,615	12,577	12,540	12,503	12,466	12,429	12,392	12,355	12,318	12,281	149,817
8.	Investment Expenses														
	a. Depreciation (C)		15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	189,516
	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)		68,185	68,032	67,879	67,725	67,572	67,419	67,266	67,113	66,959	66,806	66,653	66,500	808,109
	a. Recoverable Costs Allocated to Energy		68,185	68,032	67,879	67,725	67,572	67,419	67,266	67,113	66,959	66,806	66,653	66,500	808,109
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		66,044	65,839	65,740	65,524	65,509	65,408	65,277	64,926	64,855	64,708	64,770	64,993	783,593
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)		$66,044	$65,839	$65,740	$65,524	$65,509	$65,408	$65,277	$64,926	$64,855	$64,708	$64,770	$64,993	$783,593

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 2.3%

(D) Line 9a x Line 10

(E) Line 9b x Line 11

DOCKET NO. 070007-EI
ECRC 2008 PROJECTION FILING
EXHIBIT NO. HTB-3, PAGES 1 - 26
DOCUMENT NO. 4

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 to December 2008

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	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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	(2,373,494)	(2,386,903)	(2,400,312)	(2,413,721)	(2,427,130)	(2,440,539)	(2,453,948)	(2,467,357)	(2,480,766)	(2,494,175)	(2,507,584)	(2,520,993)	(2,534,402)	
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)	$2,644,240	2,630,831	2,617,422	2,604,013	2,590,604	2,577,195	2,563,786	2,550,377	2,536,968	2,523,559	2,510,150	2,496,741	2,483,332	
6.	Average Net Investment		2,637,536	2,624,127	2,610,718	2,597,309	2,583,900	2,570,491	2,557,082	2,543,673	2,530,264	2,516,855	2,503,446	2,490,037	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		19,394	19,296	19,197	19,098	19,000	18,901	18,803	18,704	18,605	18,507	18,408	18,310	$226,223
	b. Debt Component (Line 6 x 2.82% x 1/12)		6,198	6,167	6,135	6,104	6,072	6,041	6,009	5,978	5,946	5,915	5,883	5,852	72,300
8.	Investment Expenses														
	a. Depreciation (C)		13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	160,908
	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)		39,001	38,872	38,741	38,611	38,481	38,351	38,221	38,091	37,960	37,831	37,700	37,571	459,431
	a. Recoverable Costs Allocated to Energy		39,001	38,872	38,741	38,611	38,481	38,351	38,221	38,091	37,960	37,831	37,700	37,571	459,431
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		37,776	37,619	37,520	37,356	37,306	37,207	37,091	36,850	36,767	36,643	36,635	36,720	445,490
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)		$37,776	$37,619	$37,520	$37,356	$37,306	$37,207	$37,091	$36,850	$36,767	$36,643	$36,635	$36,720	$445,490

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(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 3.3% and 3.1%
(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 2008 to December 2008

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 January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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	(303,077)	(304,593)	(306,109)	(307,625)	(309,141)	(310,657)	(312,173)	(313,689)	(315,205)	(316,721)	(318,237)	(319,753)	(321,269)	
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)	$563,134	561,618	560,102	558,586	557,070	555,554	554,038	552,522	551,006	549,490	547,974	546,458	544,942	
6.	Average Net Investment		562,376	560,860	559,344	557,828	556,312	554,796	553,280	551,764	550,248	548,732	547,216	545,700	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,135	4,124	4,113	4,102	4,091	4,080	4,068	4,057	4,046	4,035	4,024	4,013	$48,888
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,322	1,318	1,314	1,311	1,307	1,304	1,300	1,297	1,293	1,290	1,286	1,282	15,624
8.	Investment Expenses														
	a. Depreciation (C)		1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	18,192
	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)		6,973	6,958	6,943	6,929	6,914	6,900	6,884	6,870	6,855	6,841	6,826	6,811	82,704
	a. Recoverable Costs Allocated to Energy		6,973	6,958	6,943	6,929	6,914	6,900	6,884	6,870	6,855	6,841	6,826	6,811	82,704
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		6,754	6,734	6,724	6,704	6,703	6,694	6,680	6,646	6,640	6,626	6,633	6,657	80,195
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)		$6,754	$6,734	$6,724	$6,704	$6,703	$6,694	$6,680	$6,646	$6,640	$6,626	$6,633	$6,657	$80,195

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 2.1%
(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 2008 to December 2008

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 January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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	(120,688)	(121,766)	(122,844)	(123,922)	(125,000)	(126,078)	(127,156)	(128,234)	(129,312)	(130,390)	(131,468)	(132,546)	(133,624)	
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)	$376,890	375,812	374,734	373,656	372,578	371,500	370,422	369,344	368,266	367,188	366,110	365,032	363,954	
6.	Average Net Investment		376,351	375,273	374,195	373,117	372,039	370,961	369,883	368,805	367,727	366,649	365,571	364,493	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,767	2,759	2,752	2,744	2,736	2,728	2,720	2,712	2,704	2,696	2,688	2,680	$32,686
	b. Debt Component (Line 6 x 2.82% x 1/12)		884	882	879	877	874	872	869	867	864	862	859	857	10,446
8.	Investment Expenses														
	a. Depreciation (C)		1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	12,936
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,729	4,719	4,709	4,699	4,688	4,678	4,667	4,657	4,646	4,636	4,625	4,615	56,068
	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		4,729	4,719	4,709	4,699	4,688	4,678	4,667	4,657	4,646	4,636	4,625	4,615	56,068
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		4,571	4,562	4,552	4,542	4,532	4,522	4,511	4,502	4,491	4,482	4,471	4,461	54,199
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,571	$4,562	$4,552	$4,542	$4,532	$4,522	$4,511	$4,502	$4,491	$4,482	$4,471	$4,461	$54,199

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 2.6%
(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 2008 to December 2008

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 January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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	(198,520)	(200,293)	(202,066)	(203,839)	(205,612)	(207,385)	(209,158)	(210,931)	(212,704)	(214,477)	(216,250)	(218,023)	(219,796)	
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)	$619,881	618,108	616,335	614,562	612,789	611,016	609,243	607,470	605,697	603,924	602,151	600,378	598,605	
6.	Average Net Investment		618,995	617,222	615,449	613,676	611,903	610,130	608,357	606,584	604,811	603,038	601,265	599,492	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,552	4,539	4,525	4,512	4,499	4,486	4,473	4,460	4,447	4,434	4,421	4,408	$53,756
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,455	1,450	1,446	1,442	1,438	1,434	1,430	1,425	1,421	1,417	1,413	1,409	17,180
8.	Investment Expenses														
	a. Depreciation (C)		1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	21,276
	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)		7,780	7,762	7,744	7,727	7,710	7,693	7,676	7,658	7,641	7,624	7,607	7,590	92,212
	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		7,780	7,762	7,744	7,727	7,710	7,693	7,676	7,658	7,641	7,624	7,607	7,590	92,212
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
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)		7,521	7,503	7,486	7,469	7,453	7,437	7,420	7,403	7,386	7,370	7,353	7,337	89,138
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,521	$7,503	$7,486	$7,469	$7,453	$7,437	$7,420	$7,403	$7,386	$7,370	$7,353	$7,337	$89,138

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 2.6%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 1 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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	(19,104)	(19,247)	(19,390)	(19,533)	(19,676)	(19,819)	(19,962)	(20,105)	(20,248)	(20,391)	(20,534)	(20,677)	(20,820)	
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)	$38,173	38,030	37,887	37,744	37,601	37,458	37,315	37,172	37,029	36,886	36,743	36,600	36,457	
6.	Average Net Investment		38,102	37,959	37,816	37,673	37,530	37,387	37,244	37,101	36,958	36,815	36,672	36,529	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		280	279	278	277	276	275	274	273	272	271	270	269	$3,294
	b. Debt Component (Line 6 x 2.82% x 1/12)		90	89	89	89	88	88	88	87	87	87	86	86	1,054
8.	Investment Expenses														
	a. Depreciation (C)		143	143	143	143	143	143	143	143	143	143	143	143	1,716
	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)		513	511	510	509	507	506	505	503	502	501	499	498	6,064
	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		513	511	510	509	507	506	505	503	502	501	499	498	6,064
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
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)		496	494	493	492	490	489	488	486	485	484	482	481	5,860
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$496	$494	$493	$492	$490	$489	$488	$486	$485	$484	$482	$481	$5,860

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 3.0%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 4 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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	(30,587)	(30,813)	(31,039)	(31,265)	(31,491)	(31,717)	(31,943)	(32,169)	(32,395)	(32,621)	(32,847)	(33,073)	(33,299)	
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)	$59,885	59,659	59,433	59,207	58,981	58,755	58,529	58,303	58,077	57,851	57,625	57,399	57,173	
6.	Average Net Investment		59,772	59,546	59,320	59,094	58,868	58,642	58,416	58,190	57,964	57,738	57,512	57,286	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		440	438	436	435	433	431	430	428	426	425	423	421	$5,166
	b. Debt Component (Line 6 x 2.82% x 1/12)		140	140	139	139	138	138	137	137	136	136	135	135	1,650
8.	Investment Expenses														
	a. Depreciation (C)		226	226	226	226	226	226	226	226	226	226	226	226	2,712
	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)		806	804	801	800	797	795	793	791	788	787	784	782	9,528
	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		806	804	801	800	797	795	793	791	788	787	784	782	9,528
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
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)		779	777	774	773	770	769	767	765	762	761	758	756	9,211
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$779	$777	$774	$773	$770	$769	$767	$765	$762	$761	$758	$756	$9,211

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 3.0%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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	(432,152)	(435,772)	(439,392)	(443,012)	(446,632)	(450,252)	(453,872)	(457,492)	(461,112)	(464,732)	(468,352)	(471,972)	(475,592)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$884,105	880,485	876,865	873,245	869,625	866,005	862,385	858,765	855,145	851,525	847,905	844,285	840,665	
6.	Average Net Investment		882,295	878,675	875,055	871,435	867,815	864,195	860,575	856,955	853,335	849,715	846,095	842,475	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		6,488	6,461	6,434	6,408	6,381	6,355	6,328	6,301	6,275	6,248	6,221	6,195	$76,095
	b. Debt Component (Line 6 x 2.82% x 1/12)		2,073	2,065	2,056	2,048	2,039	2,031	2,022	2,014	2,005	1,997	1,988	1,980	24,318
8.	Investment Expenses														
	a. Depreciation (C)		3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	43,440
	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)		12,181	12,146	12,110	12,076	12,040	12,006	11,970	11,935	11,900	11,865	11,829	11,795	143,853
	a. Recoverable Costs Allocated to Energy		12,181	12,146	12,110	12,076	12,040	12,006	11,970	11,935	11,900	11,865	11,829	11,795	143,853
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		11,799	11,754	11,728	11,684	11,672	11,648	11,616	11,546	11,526	11,492	11,495	11,528	139,488
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)		$11,799	$11,754	$11,728	$11,684	$11,672	$11,648	$11,616	$11,546	$11,526	$11,492	$11,495	$11,528	$139,488

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 3.3%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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	(338,166)	(340,710)	(343,254)	(345,798)	(348,342)	(350,886)	(353,430)	(355,974)	(358,518)	(361,062)	(363,606)	(366,150)	(368,694)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$646,628	644,084	641,540	638,996	636,452	633,908	631,364	628,820	626,276	623,732	621,188	618,644	616,100	
6.	Average Net Investment		645,356	642,812	640,268	637,724	635,180	632,636	630,092	627,548	625,004	622,460	619,916	617,372	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,745	4,727	4,708	4,689	4,671	4,652	4,633	4,614	4,596	4,577	4,558	4,540	$55,710
	b. Debt Component (Line 6 x 2.82% x 1/12)		1,517	1,511	1,505	1,499	1,493	1,487	1,481	1,475	1,469	1,463	1,457	1,451	17,808
8.	Investment Expenses														
	a. Depreciation (C)		2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	30,528
	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)		8,806	8,782	8,757	8,732	8,708	8,683	8,658	8,633	8,609	8,584	8,559	8,535	104,046
	a. Recoverable Costs Allocated to Energy		8,806	8,782	8,757	8,732	8,708	8,683	8,658	8,633	8,609	8,584	8,559	8,535	104,046
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		8,530	8,499	8,481	8,448	8,442	8,424	8,402	8,352	8,338	8,314	8,317	8,342	100,889
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)		$8,530	$8,499	$8,481	$8,448	$8,442	$8,424	$8,402	$8,352	$8,338	$8,314	$8,317	$8,342	$100,889

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 3.1%
(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 2008 to December 2008

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 January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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	(21,235)	(21,436)	(21,637)	(21,838)	(22,039)	(22,240)	(22,441)	(22,642)	(22,843)	(23,044)	(23,245)	(23,446)	(23,647)	
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)	$99,502	99,301	99,100	98,899	98,698	98,497	98,296	98,095	97,894	97,693	97,492	97,291	97,090	
6.	Average Net Investment		99,402	99,201	99,000	98,799	98,598	98,397	98,196	97,995	97,794	97,593	97,392	97,191	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		731	729	728	726	725	724	722	721	719	718	716	715	$8,674
	b. Debt Component (Line 6 x 2.82% x 1/12)		234	233	233	232	232	231	231	230	230	229	229	228	2,772
8.	Investment Expenses														
	a. Depreciation (C)		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	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)		1,166	1,163	1,162	1,159	1,158	1,156	1,154	1,152	1,150	1,148	1,146	1,144	13,858
	a. Recoverable Costs Allocated to Energy		1,166	1,163	1,162	1,159	1,158	1,156	1,154	1,152	1,150	1,148	1,146	1,144	13,858
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		1,129	1,126	1,125	1,121	1,123	1,122	1,120	1,114	1,114	1,112	1,114	1,118	13,438
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)		$1,129	$1,126	$1,125	$1,121	$1,123	$1,122	$1,120	$1,114	$1,114	$1,112	$1,114	$1,118	$13,438

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 2.0%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD (Less Gypsum Revenue)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$487,100	$487,100	$496,100	$495,700	$1,966,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	210,000	210,000
	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)	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,552,961	$83,762,961	
3.	Less: Accumulated Depreciation	(26,919,562)	(27,121,365)	(27,323,168)	(27,524,971)	(27,726,774)	(27,928,577)	(28,130,380)	(28,332,183)	(28,533,986)	(28,735,789)	(28,937,592)	(29,139,395)	(29,341,399)	
4.	CWIP - Non-Interest Bearing	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	504,100	991,200	1,487,300	1,773,000	
5.	Net Investment (Lines 2 + 3 + 4)	$56,650,399	56,448,596	56,246,793	56,044,990	55,843,187	55,641,384	55,439,581	55,237,778	55,035,975	55,321,272	55,606,569	55,900,866	56,194,562	
6.	Average Net Investment		56,549,497	56,347,694	56,145,891	55,944,088	55,742,285	55,540,482	55,338,679	55,136,876	55,178,623	55,463,920	55,753,717	56,047,714	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		415,818	414,334	412,850	411,366	409,882	408,398	406,915	405,431	405,738	407,835	409,966	412,128	$4,920,661
	b. Debt Component (Line 6 x 2.82% x 1/12)		132,891	132,417	131,943	131,469	130,994	130,520	130,046	129,572	129,670	130,340	131,021	131,712	1,572,595
8.	Investment Expenses														
	a. Depreciation (C)		201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	201,803	202,004	2,421,837
	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)		750,512	748,554	746,596	744,638	742,679	740,721	738,764	736,806	737,211	739,978	742,790	745,844	8,915,093
	a. Recoverable Costs Allocated to Energy		750,512	748,554	746,596	744,638	742,679	740,721	738,764	736,806	737,211	739,978	742,790	745,844	8,915,093
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		726,948	724,421	723,075	720,442	720,010	718,622	716,915	712,793	714,044	716,743	721,803	728,943	8,644,759
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)		$726,948	$724,421	$723,075	$720,442	$720,010	$718,622	$716,915	$712,793	$714,044	$716,743	$721,803	$728,943	$8,644,759

Notes:

(A) Applicable depreciable base for Big Bend; account 312.46 ($83,318,932) and 312.45 ($444,029)
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rates are 2.9% and 2.3%.
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	
3.	Less: Accumulated Depreciation	(3,532,381)	(3,574,023)	(3,615,665)	(3,657,307)	(3,698,949)	(3,740,591)	(3,782,233)	(3,823,875)	(3,865,517)	(3,907,159)	(3,948,801)	(3,990,443)	(4,032,085)	
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)	$18,207,356	18,165,714	18,124,072	18,082,430	18,040,788	17,999,146	17,957,504	17,915,862	17,874,220	17,832,578	17,790,936	17,749,294	17,707,652	
6.	Average Net Investment		18,186,535	18,144,893	18,103,251	18,061,609	18,019,967	17,978,325	17,936,683	17,895,041	17,853,399	17,811,757	17,770,115	17,728,473	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		133,729	133,422	133,116	132,810	132,504	132,198	131,891	131,585	131,279	130,973	130,667	130,360	$1,584,534
	b. Debt Component (Line 6 x 2.82% x 1/12)		42,738	42,640	42,543	42,445	42,347	42,249	42,151	42,053	41,955	41,858	41,760	41,662	506,401
8.	Investment Expenses														
	a. Depreciation (C)		41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	499,704
	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)		218,109	217,704	217,301	216,897	216,493	216,089	215,684	215,280	214,876	214,473	214,069	213,664	2,590,639
	a. Recoverable Costs Allocated to Energy		218,109	217,704	217,301	216,897	216,493	216,089	215,684	215,280	214,876	214,473	214,069	213,664	2,590,639
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		211,261	210,685	210,455	209,849	209,885	209,642	209,305	208,264	208,123	207,739	208,021	208,822	2,512,051
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)		$211,261	$210,685	$210,455	$209,849	$209,885	$209,642	$209,305	$208,264	$208,123	$207,739	$208,021	$208,822	$2,512,051

Notes:

(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45 ($21,699,919)
(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 1.5% and 2.3%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$80,000	$80,000	$80,000	$85,000	$10,000	$10,000	$15,000	$15,000	$375,000
	b. Clearings to Plant		0	0	0	0	0	0	0	300,000	0	0	0	0	300,000
	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)	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,128,210	$6,428,210	$6,428,210	$6,428,210	$6,428,210	$6,428,210	
3.	Less: Accumulated Depreciation	(422,927)	(438,854)	(454,781)	(470,708)	(486,635)	(502,562)	(518,489)	(534,416)	(550,668)	(567,245)	(583,822)	(600,399)	(616,976)	
4.	CWIP - Non-Interest Bearing	50,000	50,000	50,000	50,000	50,000	130,000	210,000	290,000	75,000	85,000	95,000	110,000	125,000	
5.	Net Investment (Lines 2 + 3 + 4)	$5,755,283	5,739,356	5,723,429	5,707,502	5,691,575	5,755,648	5,819,721	5,883,794	5,952,542	5,945,965	5,939,388	5,937,811	5,936,234	
6.	Average Net Investment		5,747,320	5,731,393	5,715,466	5,699,539	5,723,612	5,787,685	5,851,758	5,918,168	5,949,254	5,942,677	5,938,600	5,937,023	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		42,261	42,144	42,027	41,910	42,087	42,558	43,029	43,517	43,746	43,697	43,668	43,656	$514,300
	b. Debt Component (Line 6 x 2.82% x 1/12)		13,506	13,469	13,431	13,394	13,450	13,601	13,752	13,908	13,981	13,965	13,956	13,952	164,365
8.	Investment Expenses														
	a. Depreciation (C)		15,927	15,927	15,927	15,927	15,927	15,927	15,927	16,252	16,577	16,577	16,577	16,577	194,049
	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)		71,694	71,540	71,385	71,231	71,464	72,086	72,708	73,677	74,304	74,239	74,201	74,185	872,714
	a. Recoverable Costs Allocated to Energy		71,694	71,540	71,385	71,231	71,464	72,086	72,708	73,677	74,304	74,239	74,201	74,185	872,714
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		69,443	69,234	69,136	68,916	69,283	69,935	70,558	71,276	71,969	71,908	72,105	72,504	846,267
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)		$69,443	$69,234	$69,136	$68,916	$69,283	$69,935	$70,558	$71,276	$71,969	$71,908	$72,105	$72,504	$846,267

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($4,013,075), and 312.43 ($439,964)
(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 3.3%, 3.1%, and 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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$75,000	$100,000	$125,000	$125,000	$50,000	$25,000	$0	$0	$0	$0	$0	$0	$500,000
	b. Clearings to Plant		0	0	0	0	475,000	25,000	0	0	0	0	0	0	500,000
	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)	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$7,991,052	$8,466,052	$8,491,052	$8,491,052	$8,491,052	$8,491,052	$8,491,052	$8,491,052	$8,491,052	
3.	Less: Accumulated Depreciation	(725,979)	(746,174)	(766,369)	(786,564)	(806,759)	(827,449)	(848,660)	(869,897)	(891,134)	(912,371)	(933,608)	(954,845)	(976,082)	
4.	CWIP - Non-Interest Bearing	0	75,000	175,000	300,000	425,000	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,265,073	7,319,878	7,399,683	7,504,488	7,609,293	7,638,603	7,642,392	7,621,155	7,599,918	7,578,681	7,557,444	7,536,207	7,514,970	
6.	Average Net Investment		7,292,476	7,359,781	7,452,086	7,556,891	7,623,948	7,640,498	7,631,774	7,610,537	7,589,300	7,568,063	7,546,826	7,525,589	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		53,623	54,118	54,796	55,567	56,060	56,182	56,118	55,962	55,805	55,649	55,493	55,337	$664,710
	b. Debt Component (Line 6 x 2.82% x 1/12)		17,137	17,295	17,512	17,759	17,916	17,955	17,935	17,885	17,835	17,785	17,735	17,685	212,434
8.	Investment Expenses														
	a. Depreciation (C)		20,195	20,195	20,195	20,195	20,690	21,211	21,237	21,237	21,237	21,237	21,237	21,237	250,103
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		90,955	91,608	92,503	93,521	94,666	95,348	95,290	95,084	94,877	94,671	94,465	94,259	1,127,247
	a. Recoverable Costs Allocated to Energy		90,955	91,608	92,503	93,521	94,666	95,348	95,290	95,084	94,877	94,671	94,465	94,259	1,127,247
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		88,099	88,655	89,589	90,482	91,776	92,503	92,472	91,985	91,895	91,698	91,796	92,123	1,093,073
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)		$88,099	$88,655	$89,589	$90,482	$91,776	$92,503	$92,472	$91,985	$91,895	$91,698	$91,796	$92,123	$1,093,073

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,513,263), 312.42 ($5,153,072), 312.43 ($955,619), 315.41 ($17,504), 315.43 ($500,000), and 315.44 ($351,594)
(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 3.3%, 3.1%, 2.6%, 2.5%, 2.5%, and 2.1%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(205,530)	(209,954)	(214,378)	(218,802)	(223,226)	(227,650)	(232,074)	(236,498)	(240,922)	(245,346)	(249,770)	(254,194)	(258,618)	
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)	$1,355,943	1,351,519	1,347,095	1,342,671	1,338,247	1,333,823	1,329,399	1,324,975	1,320,551	1,316,127	1,311,703	1,307,279	1,302,855	
6.	Average Net Investment		1,353,731	1,349,307	1,344,883	1,340,459	1,336,035	1,331,611	1,327,187	1,322,763	1,318,339	1,313,915	1,309,491	1,305,067	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		9,954	9,922	9,889	9,857	9,824	9,792	9,759	9,726	9,694	9,661	9,629	9,596	$117,303
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,181	3,171	3,160	3,150	3,140	3,129	3,119	3,108	3,098	3,088	3,077	3,067	37,488
8.	Investment Expenses														
	a. Depreciation (C)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,559	17,517	17,473	17,431	17,388	17,345	17,302	17,258	17,216	17,173	17,130	17,087	207,879
	a. Recoverable Costs Allocated to Energy		17,559	17,517	17,473	17,431	17,388	17,345	17,302	17,258	17,216	17,173	17,130	17,087	207,879
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		17,008	16,952	16,923	16,865	16,857	16,828	16,790	16,696	16,675	16,634	16,646	16,700	201,574
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)		$17,008	$16,952	$16,923	$16,865	$16,857	$16,828	$16,790	$16,696	$16,675	$16,634	$16,646	$16,700	$201,574

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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(203,234)	(208,351)	(213,468)	(218,585)	(223,702)	(228,819)	(233,936)	(239,053)	(244,170)	(249,287)	(254,404)	(259,521)	(264,638)	
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)	$2,355,496	2,350,379	2,345,262	2,340,145	2,335,028	2,329,911	2,324,794	2,319,677	2,314,560	2,309,443	2,304,326	2,299,209	2,294,092	
6.	Average Net Investment		2,352,938	2,347,821	2,342,704	2,337,587	2,332,470	2,327,353	2,322,236	2,317,119	2,312,002	2,306,885	2,301,768	2,296,651	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		17,302	17,264	17,226	17,189	17,151	17,113	17,076	17,038	17,001	16,963	16,925	16,888	$205,136
	b. Debt Component (Line 6 x 2.82% x 1/12)		5,529	5,517	5,505	5,493	5,481	5,469	5,457	5,445	5,433	5,421	5,409	5,397	65,556
8.	Investment Expenses														
	a. Depreciation (C)		5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	61,404
	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)		27,948	27,898	27,848	27,799	27,749	27,699	27,650	27,600	27,551	27,501	27,451	27,402	332,096
	a. Recoverable Costs Allocated to Energy		27,948	27,898	27,848	27,799	27,749	27,699	27,650	27,600	27,551	27,501	27,451	27,402	332,096
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		27,071	26,999	26,971	26,896	26,902	26,873	26,832	26,701	26,685	26,637	26,675	26,781	322,023
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)		$27,071	$26,999	$26,971	$26,896	$26,902	$26,873	$26,832	$26,701	$26,685	$26,637	$26,675	$26,781	$322,023

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 2.4%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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	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)	$1,649,121	$1,653,621	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(52,165)	(56,700)	(61,235)	(65,770)	(70,305)	(74,840)	(79,375)	(83,910)	(88,445)	(92,980)	(97,515)	(102,050)	(106,585)	
4.	CWIP - Non-Interest Bearing	363,967	363,967	363,967	363,967	363,967	363,967	363,967	363,967	363,967	363,967	363,967	363,967	363,967	
5.	Net Investment (Lines 2 + 3 + 4)	$1,960,923	1,960,888	1,951,853	1,947,318	1,942,783	1,938,248	1,933,713	1,929,178	1,924,643	1,920,108	1,915,573	1,911,038	1,906,503	
6.	Average Net Investment		1,960,906	1,956,371	1,949,586	1,945,051	1,940,516	1,935,981	1,931,446	1,926,911	1,922,376	1,917,841	1,913,306	1,908,771	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		14,419	14,386	14,336	14,302	14,269	14,236	14,202	14,169	14,136	14,102	14,069	14,036	$170,662
	b. Debt Component (Line 6 x 2.82% x 1/12)		4,608	4,597	4,582	4,571	4,560	4,550	4,539	4,528	4,518	4,507	4,496	4,486	54,542
8.	Investment Expenses														
	a. Depreciation (C)		4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	54,420
	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)		23,562	23,518	23,453	23,408	23,364	23,321	23,276	23,232	23,189	23,144	23,100	23,057	279,624
	a. Recoverable Costs Allocated to Energy		23,562	23,518	23,453	23,408	23,364	23,321	23,276	23,232	23,189	23,144	23,100	23,057	279,624
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		22,822	22,760	22,714	22,647	22,651	22,625	22,588	22,475	22,460	22,417	22,447	22,535	271,141
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)		$22,822	$22,760	$22,714	$22,647	$22,651	$22,625	$22,588	$22,475	$22,460	$22,417	$22,447	$22,535	$271,141

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 3.3%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(47,000)	(51,087)	(55,174)	(59,261)	(63,348)	(67,435)	(71,522)	(75,609)	(79,696)	(83,783)	(87,870)	(91,957)	(96,044)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,534,887	1,530,800	1,526,713	1,522,626	1,518,539	1,514,452	1,510,365	1,506,278	1,502,191	1,498,104	1,494,017	1,489,930	1,485,843	
6.	Average Net Investment		1,532,844	1,528,757	1,524,670	1,520,583	1,516,496	1,512,409	1,508,322	1,504,235	1,500,148	1,496,061	1,491,974	1,487,887	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		11,271	11,241	11,211	11,181	11,151	11,121	11,091	11,061	11,031	11,001	10,971	10,941	$133,272
	b. Debt Component (Line 6 x 2.82% x 1/12)		3,602	3,593	3,583	3,573	3,564	3,554	3,545	3,535	3,525	3,516	3,506	3,497	42,593
8.	Investment Expenses														
	a. Depreciation (C)		4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	49,044
	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)		18,960	18,921	18,881	18,841	18,802	18,762	18,723	18,683	18,643	18,604	18,564	18,525	224,909
	a. Recoverable Costs Allocated to Energy		18,960	18,921	18,881	18,841	18,802	18,762	18,723	18,683	18,643	18,604	18,564	18,525	224,909
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		18,365	18,311	18,286	18,229	18,228	18,202	18,169	18,074	18,057	18,020	18,039	18,105	218,085
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)		$18,365	$18,311	$18,286	$18,229	$18,228	$18,202	$18,169	$18,074	$18,057	$18,020	$18,039	$18,105	$218,085

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 3.1%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$114,200	$152,200	$319,300	$190,300	$76,100	$37,900	$0	$0	$0	$0	$0	$0	$890,000
	b. Clearings to Plant		0	0	0	3,321,097	76,100	37,900	0	0	0	0	0	0	3,435,097
	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	$3,321,097	$3,397,197	$3,435,097	$3,435,097	$3,435,097	$3,435,097	$3,435,097	$3,435,097	$3,435,097	
3.	Less: Accumulated Depreciation	0	0	0	0	(3,568)	(10,787)	(18,130)	(25,514)	(32,898)	(40,282)	(47,666)	(55,050)	(62,434)	
4.	CWIP - Non-Interest Bearing	2,545,097	2,659,297	2,811,497	3,130,797	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,545,097	2,659,297	2,811,497	3,130,797	3,317,529	3,386,410	3,416,967	3,409,583	3,402,199	3,394,815	3,387,431	3,380,047	3,372,663	
6.	Average Net Investment		2,602,197	2,735,397	2,971,147	3,224,163	3,351,970	3,401,689	3,413,275	3,405,891	3,398,507	3,391,123	3,383,739	3,376,355	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		19,134	20,114	21,847	23,708	24,648	25,013	25,098	25,044	24,990	24,935	24,881	24,827	$284,239
	b. Debt Component (Line 6 x 2.82% x 1/12)		6,115	6,428	6,982	7,577	7,877	7,994	8,021	8,004	7,986	7,969	7,952	7,934	90,839
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	3,568	7,219	7,343	7,384	7,384	7,384	7,384	7,384	7,384	62,434
	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)		25,249	26,542	28,829	34,853	39,744	40,350	40,503	40,432	40,360	40,288	40,217	40,145	437,512
	a. Recoverable Costs Allocated to Energy		25,249	26,542	28,829	34,853	39,744	40,350	40,503	40,432	40,360	40,288	40,217	40,145	437,512
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		24,456	25,686	27,921	33,720	38,531	39,146	39,305	39,114	39,092	39,023	39,081	39,235	424,310
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)		$24,456	$25,686	$27,921	$33,720	$38,531	$39,146	$39,305	$39,114	$39,092	$39,023	$39,081	$39,235	$424,310

Notes:

(A) Applicable depreciable base for Big Bend; account 312.43 ($2,724,267) and 315.43 ($710,830)
(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% and 2.5%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$1,194,577	$857,573	$610,490	$608,245	$433,244	$583,511	$1,559,709	$1,336,034	$1,881,997	$3,308,471	$1,657,239	$1,422,100	$15,453,190
	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)	$28,245,555	$29,440,132	$30,297,705	$30,908,195	$31,516,440	$31,949,684	$32,533,195	$34,092,904	$35,428,938	$37,310,935	$40,619,406	$42,276,645	$43,698,745	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$28,245,555	29,440,132	30,297,705	30,908,195	31,516,440	31,949,684	32,533,195	34,092,904	35,428,938	37,310,935	40,619,406	42,276,645	43,698,745	
6.	Average Net Investment		28,842,844	29,868,919	30,602,950	31,212,318	31,733,062	32,241,440	33,313,050	34,760,921	36,369,937	38,965,171	41,448,026	42,987,695	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41 and 315.41. These dollars are for tracking purposes only; depreciation and return are not calculated until the project goes in to service.
(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 are 3.3% and 2.5%.
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$6,410,390	$2,663,758	$4,718,150	$2,984,604	$2,521,269	$3,091,247	$2,658,703	$2,527,843	$3,113,269	$3,514,014	$4,259,416	$2,832,421	$41,295,084
	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)	$35,211,612	$41,622,002	$44,285,760	$49,003,910	$51,988,514	$54,509,783	$57,601,030	$60,259,733	$62,787,576	$65,900,845	$69,414,859	$73,674,275	$76,506,696	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$35,211,612	41,622,002	44,285,760	49,003,910	51,988,514	54,509,783	57,601,030	60,259,733	62,787,576	65,900,845	69,414,859	73,674,275	76,506,696	
6.	Average Net Investment		38,416,807	42,953,881	46,644,835	50,496,212	53,249,149	56,055,407	58,930,382	61,523,655	64,344,211	67,657,852	71,544,567	75,090,486	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) Applicable depreciable base for Big Bend; account 312.42 and 312.44. These dollars are for tracking purposes only; depreciation and return are not calculated until the project goes in to service.
(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 3.1% and 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) FPSC ruling in Docket No. 980693-EI does not allow for recovery of dollars associated with this project until placed in-service.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$2,745,448	$2,725,065	$2,650,862	$2,101,525	$1,794,928	$907,213	$830,715	$671,303	$671,303	$681,303	$681,303	$840,503	$17,301,471
	b. Clearings to Plant		0	0	0	80,579,231	1,794,928	907,213	830,715	671,303	671,303	681,303	681,303	840,503	87,657,802
	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)	$66,414,356	$69,159,804	$71,884,869	$74,535,731	$80,579,231	$82,374,159	$83,281,372	$84,112,087	$84,783,390	$85,454,693	$86,135,996	$86,817,299	$87,657,802	
3.	Less: Accumulated Depreciation	0	0	0	0	(85,168)	(257,447)	(432,654)	(609,743)	(788,460)	(968,631)	(1,150,267)	(1,333,380)	(1,518,141)	
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)	$66,414,356	69,159,804	71,884,869	74,535,731	80,494,063	82,116,712	82,848,718	83,502,344	83,994,930	84,486,062	84,985,729	85,483,919	86,139,661	
6.	Average Net Investment		67,787,080	70,522,337	73,210,300	77,514,897	81,305,388	82,482,715	83,175,531	83,748,637	84,240,496	84,735,896	85,234,824	85,811,790	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	569,980	597,852	606,509	611,604	615,818	619,434	623,077	626,746	630,988	$5,502,008
	b. Debt Component (Line 6 x 2.82% x 1/12)		0	0	0	182,160	191,068	193,834	195,462	196,809	197,965	199,129	200,302	201,658	1,758,387
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	85,168	172,279	175,207	177,089	178,717	180,171	181,636	183,113	184,761	1,518,141
	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	837,308	961,199	975,550	984,155	991,344	997,570	1,003,842	1,010,161	1,017,407	8,778,536
	a. Recoverable Costs Allocated to Energy		0	0	0	837,308	961,199	975,550	984,155	991,344	997,570	1,003,842	1,010,161	1,017,407	8,778,536
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	810,101	931,860	946,445	955,049	959,036	966,221	972,321	981,620	994,353	8,517,006
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F		$0	$0	$0	$810,101	$931,860	$946,445	$955,049	$959,036	$966,221	$972,321	$981,620	$994,353	$8,517,006

Notes:

(A) Applicable depreciable base for Big Bend; accounts 311.43 ($2,939,080), 312.43 ($79,772,165), and 312.44 ($4,946,557)

(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 1.2%, 2.6%, and 2.4%

(D) Line 9a x Line 10

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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	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)	$61,896,655	$61,896,655	$61,896,655	$61,896,655	$61,896,655	$61,896,655	$61,896,655	$61,896,655	$61,896,655	$61,896,655	$61,896,655	$61,896,655	$61,896,655	
3.	Less: Accumulated Depreciation	(915,952)	(1,039,745)	(1,163,538)	(1,287,331)	(1,411,124)	(1,534,917)	(1,658,710)	(1,782,503)	(1,906,296)	(2,030,089)	(2,153,882)	(2,277,675)	(2,401,468)	
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)	$60,980,703	60,856,910	60,733,117	60,609,324	60,485,531	60,361,738	60,237,945	60,114,152	59,990,359	59,866,566	59,742,773	59,618,980	59,495,187	
6.	Average Net Investment		60,918,807	60,795,014	60,671,221	60,547,428	60,423,635	60,299,842	60,176,049	60,052,256	59,928,463	59,804,670	59,680,877	59,557,084	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		86,699	86,523	86,347	86,171	85,995	443,395	442,485	441,574	440,664	439,754	438,843	437,933	$3,516,383
	b. Debt Component (Line 6 x 2.82% x 1/12)		27,708	27,652	27,596	27,539	27,483	141,705	141,414	141,123	140,832	140,541	140,250	139,959	1,123,802
8.	Investment Expenses														
	a. Depreciation (C)		123,793	123,793	123,793	123,793	123,793	123,793	123,793	123,793	123,793	123,793	123,793	123,793	1,485,516
	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)		238,200	237,968	237,736	237,503	237,271	708,893	707,692	706,490	705,289	704,088	702,886	701,685	6,125,701
	a. Recoverable Costs Allocated to Energy		238,200	237,968	237,736	237,503	237,271	708,893	707,692	706,490	705,289	704,088	702,886	701,685	6,125,701
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		230,721	230,296	230,246	229,786	230,029	687,743	686,762	683,465	683,125	681,979	683,027	685,785	5,942,964
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$230,721	$230,296	$230,246	$229,786	$230,029	$687,743	$686,762	$683,465	$683,125	$681,979	$683,027	$685,785	$5,942,964

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 2.4%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$300,400	$393,800	$487,300	$487,300	$206,900	$108,300	$20,000	$20,000	$420,000	$420,000	$420,000	$420,000	$3,704,000
	b. Clearings to Plant		0	0	0	5,895,888	186,900	93,300	0	0	0	0	0	0	6,176,088
	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)	$5,007,902	$5,007,902	$5,007,902	$5,007,902	$10,903,790	$11,090,690	$11,183,990	$11,183,990	$11,183,990	$11,183,990	$11,183,990	$11,183,990	$11,183,990	
3.	Less: Accumulated Depreciation	(71,152)	(80,750)	(90,348)	(99,946)	(115,279)	(136,528)	(158,049)	(179,661)	(201,273)	(222,885)	(244,497)	(266,109)	(287,721)	
4.	CWIP - Non-Interest Bearing	4,753,581	5,053,981	5,447,781	5,935,081	526,493	546,493	561,493	581,493	601,493	1,021,493	1,441,493	1,861,493	2,281,493	
5.	Net Investment (Lines 2 + 3 + 4)	$9,690,331	9,981,133	10,365,335	10,843,037	11,315,004	11,500,655	11,587,434	11,585,822	11,584,210	11,982,598	12,380,986	12,779,374	13,177,762	
6.	Average Net Investment		9,835,732	10,173,234	10,604,186	11,079,021	11,407,830	11,544,045	11,586,628	11,585,016	11,783,404	12,181,792	12,580,180	12,978,568	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		72,324	74,805	77,974	81,466	83,884	84,885	85,198	85,187	86,645	89,575	92,504	95,434	$1,009,881
	b. Debt Component (Line 6 x 2.82% x 1/12)		23,114	23,907	24,920	26,036	26,808	27,129	27,229	27,225	27,691	28,627	29,563	30,500	322,749
8.	Investment Expenses														
	a. Depreciation (C)		9,598	9,598	9,598	15,333	21,249	21,521	21,612	21,612	21,612	21,612	21,612	21,612	216,569
	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)		105,036	108,310	112,492	122,835	131,941	133,535	134,039	134,024	135,948	139,814	143,679	147,546	1,549,199
	a. Recoverable Costs Allocated to Energy		105,036	108,310	112,492	122,835	131,941	133,535	134,039	134,024	135,948	139,814	143,679	147,546	1,549,199
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		101,738	104,818	108,948	118,844	127,914	129,551	130,075	129,656	131,676	135,424	139,619	144,203	1,502,466
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)		$101,738	$104,818	$108,948	$118,844	$127,914	$129,551	$130,075	$129,656	$131,676	$135,424	$139,619	$144,203	$1,502,466

Notes:

(A) Applicable depreciable base for Big Bend; account 312.44 ($2,114,410) and 312.45 ($9,069,580)
(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% and 2.3%
(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 2008 to December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Air Mercury Rule
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$115,000	$335,000	$5,000	$5,000	$5,000	$1,104,670	$5,000	$5,000	$5,000	$5,000	$5,000	$122,763	$1,717,433
	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	115,000	450,000	455,000	460,000	465,000	1,569,670	1,574,670	1,579,670	1,584,670	1,589,670	1,594,670	1,717,433	
5.	Net Investment (Lines 2 + 3 + 4)	$0	115,000	450,000	455,000	460,000	465,000	1,569,670	1,574,670	1,579,670	1,584,670	1,589,670	1,594,670	1,717,433	
6.	Average Net Investment		57,500	282,500	452,500	457,500	462,500	1,017,335	1,572,170	1,577,170	1,582,170	1,587,170	1,592,170	1,656,052	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		423	2,077	3,327	3,364	3,401	7,481	11,560	11,597	11,634	11,671	11,707	12,177	$90,419
	b. Debt Component (Line 6 x 2.82% x 1/12)		135	664	1,063	1,075	1,087	2,391	3,695	3,706	3,718	3,730	3,742	3,892	28,898
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)		558	2,741	4,390	4,439	4,488	9,872	15,255	15,303	15,352	15,401	15,449	16,069	119,317
	a. Recoverable Costs Allocated to Energy		558	2,741	4,390	4,439	4,488	9,872	15,255	15,303	15,352	15,401	15,449	16,069	119,317
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (D)		540	2,653	4,252	4,295	4,351	9,577	14,804	14,804	14,870	14,917	15,013	15,705	115,781
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)		$540	$2,653	$4,252	$4,295	$4,351	$9,577	$14,804	$14,804	$14,870	$14,917	$15,013	$15,705	$115,781

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 315.40, 315.42, 315.43, 315.44, and 345.80
(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 3.0%, 2.5%, 2.5%, 2.1%, and 2.4%
(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 2008 to December 2008

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	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		2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	30,000,000
	c. Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Working Capital Balance														
	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 254.01 Regulatory Liabilities - Gains	(130,952)	(122,516)	(114,294)	(105,905)	(97,052)	(88,018)	(79,025)	(69,945)	(60,840)	(51,910)	(42,893)	(33,987)	(25,321)	
3.	Total Working Capital Balance	($130,952)	(122,516)	(114,294)	(105,905)	(97,052)	(88,018)	(79,025)	(69,945)	(60,840)	(51,910)	(42,893)	(33,987)	(25,321)	
4.	Average Net Working Capital Balance		($126,734)	($118,405)	($110,099)	($101,479)	($92,535)	($83,522)	($74,485)	($65,393)	($56,375)	($47,401)	($38,440)	($29,654)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(932)	(871)	(810)	(746)	(680)	(614)	(548)	(481)	(415)	(349)	(283)	(218)	(6,947)
	b. Debt Component (Line 4 x 2.82% x 1/12)		(298)	(278)	(259)	(238)	(217)	(196)	(175)	(154)	(132)	(111)	(90)	(70)	(2,218)
6.	Total Return Component		(1,230)	(1,149)	(1,069)	(984)	(897)	(810)	(723)	(635)	(547)	(460)	(373)	(288)	(9,165)
7.	Expenses:														
	a. Gains		(2,506,875)	(2,506,875)	(2,506,875)	(2,506,875)	(2,506,875)	(2,506,875)	(2,506,875)	(2,506,875)	(2,506,938)	(2,506,875)	(2,506,938)	(2,506,938)	(30,082,689)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		56,039	50,853	56,086	55,722	57,441	55,583	57,395	57,370	55,708	57,458	53,732	55,872	669,259
8.	Net Expenses (B)		(2,450,836)	(2,456,022)	(2,450,789)	(2,451,153)	(2,449,434)	(2,451,292)	(2,449,480)	(2,449,505)	(2,451,230)	(2,449,417)	(2,453,206)	(2,451,066)	(29,413,430)
9.	Total System Recoverable Expenses (Lines 6 + 8)		(2,452,066)	(2,457,171)	(2,451,858)	(2,452,137)	(2,450,331)	(2,452,102)	(2,450,203)	(2,450,140)	(2,451,777)	(2,449,877)	(2,453,579)	(2,451,354)	(29,422,595)
	a. Recoverable Costs Allocated to Energy		(2,452,066)	(2,457,171)	(2,451,858)	(2,452,137)	(2,450,331)	(2,452,102)	(2,450,203)	(2,450,140)	(2,451,777)	(2,449,877)	(2,453,579)	(2,451,354)	(29,422,595)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9686032	0.9677600	0.9684954	0.9675060	0.9694763	0.9701651	0.9704255	0.9674099	0.9685746	0.9685998	0.9717460	0.9773401	
11.	Demand Jurisdictional Factor		0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	
12.	Retail Energy-Related Recoverable Costs (C)		(2,375,079)	(2,377,952)	(2,374,613)	(2,372,457)	(2,375,538)	(2,378,944)	(2,377,739)	(2,370,290)	(2,374,729)	(2,372,950)	(2,384,256)	(2,395,807)	(28,530,354)
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)		($2,375,079)	($2,377,952)	($2,374,613)	($2,372,457)	($2,375,538)	($2,378,944)	($2,377,739)	($2,370,290)	($2,374,729)	($2,372,950)	($2,384,256)	($2,395,807)	($28,530,354)

Notes:
(A) Line 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 6 is reported on Schedule 6P and 7P
(C) Line 8 is reported on Schedule 4P and 5P
(D) Line 9a x Line 10
(E) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

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Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 3 Flue Gas Desulfurization Integration

Project Description:

This project involved the integration of Big Bend Unit 3 flue gases into the Big Bend Unit 4 Flue Gas Desulfurization ("FGD") system. The integration was accomplished by installing interconnecting ductwork between Unit 3 precipitator outlet ducts and the Unit 4 FGD inlet duct. The Unit 4 FGD outlet duct was interconnected with the Unit 3 chimney via new ductwork and a new stack breaching. New ductwork, linings, isolation dampers, support steel, and stack annulus pressurization fans were procured and installed. Modifications to the materials handling systems and controls were also necessary.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007, is $830,177 compared to the original projection of $868,973, representing an insignificant variance.

The actual/estimated O&M expense for the period January 2007 through December 2007 is $4,514,051 compared to the original projection of $4,013,300 representing a variance of 12.5%. This variance is due to the increase in common maintenance performed on Units 3 and 4 due to the Unit 4 outage.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008, is expected to be $808,109.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $3,688,900.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Units 1 & 2 Flue Gas Conditioning

Project Description:

The existing electrostatic precipitators were not designed for the range of fuels needed for compliance with the Clean Air Act Amendments ("CAAA"). Flue gas conditioning was required to assure operation of the generating units in accordance with applicable permits and regulations. This equipment is still required to ensure compliance with the CAAA in the event the FGD system on Units 1 & 2 is not operating.

The project involved the addition of molten sulfur unloading, storage and conveying to sulfur burners and catalytic converters where SO_2 is converted to SO_3. The control and injection system then injects this into the ductwork ahead of the electrostatic precipitators.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $478,165 compared to the original projection of $512,817 representing an insignificant variance.

The actual/estimated O&M expense for this project for the period January 2007 through December 2007 is $0 and did not vary from the original projection.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $459,431.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $0.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 4 Continuous Emissions Monitors

Project Description:

Continuous emissions monitors (CEMs) were installed on the flue gas inlet and outlet of Big Bend Unit 4 to monitor compliance with the CAAA requirements. The monitors are capable of measuring, recording and electronically reporting SO_2, NO_x and volumetric gas flow out of the stack. The project consisted of monitors, a CEM building, the CEMs control and power cables to supply a complete system.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMs and specific requirements for the monitoring of pollutants, opacity and volumetric flow. These regulations are very comprehensive and specific as to the requirements for CEMs, and in essence, they define the components needed and their configuration.

Project Accomplishment:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $84,822 compared to the original projection of $89,714 representing an insignificant variance.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $82,704.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 1 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 1 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements will optimize coal fineness by providing a 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:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $148,910 compared to the original projection of $155,105 representing an insignificant variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $143,853.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 2 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 2 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements will optimize coal fineness by providing a more uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, will enable a uniform, staged combustion. As a result, firing systems will operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $107,596 compared to the original projection of $116,875 representing an insignificant variance.

Progress Summary: The project was placed in-service May 1998.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $104,046.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Units 1 & 2 FGD

Project Description:

The Big Bend Units 1 & 2 FGD system consists of equipment capable of removing SO_2 from the flue gas generated by the combustion of coal. The FGD was installed in order to comply with Phase II of the CAAA. Compliance with Phase II is required by January 1, 2000. The CAAA impose SO_2 emission limits on existing steam electric units with an output capacity of greater than 25 megawatts and all new utility units. Tampa Electric conducted an exhaustive analysis of options to comply with Phase II of the CAAA that culminated in the selection of the FGD project to serve Big Bend Units 1 & 2.

In Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999, the Commission found that the FGD project was the most cost-effective alternative for compliance with the SO_2 requirements of Phase II of the CAAA.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $9,156,955 compared to the original projection of $10,119,550 representing an insignificant variance.

The actual/estimated O&M expense for the period January 2007 through December 2007 is $5,477,691 as compared to the original estimate of $6,621,900 resulting in a variance of 17.3%. This variance is primarily due to the ability to coordinate maintenance activity with scheduled outages.

Progress Summary: The project was placed in-service in December 1999.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is expected to be $8,915,093.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $7,243,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Section 114 Mercury Testing Platform

Project Description:

The Mercury Emissions Information Collection Effort is mandated by the EPA. The EPA asserts that Section 114 of the CAAA grants to the EPA the authority to request the collection of information necessary for it to study whether it is appropriate and necessary to develop performance or emission standards for electric utility steam generating units.

In a letter dated November 25, 1998, Tampa Electric was notified by the EPA that, pursuant to Section 114 of the CAAA, the company was required to periodically sample and analyze coal shipments for mercury and chlorine content during the period January 1, 1999 through December 31, 1999.

In addition to coal sampling, stack testing and analyses are also required. Tampa Electric received a second letter from EPA, dated March 11, 1999, requiring Tampa Electric to perform specialized 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:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007, is $14,137 compared to the original projection of $14,478 representing an insignificant variance.

Progress Summary: The project was placed in-service in December 1999 and was completed in May 2000.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is expected to be $13,858.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend FGD Optimization and Utilization

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment 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 required on the Unit 3 tower module included the tower piping, nozzle and internal improvements, ductwork improvements, electrical system reliability improvements, tower control improvements, dibasic acid system improvements, booster fan reliability, 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 de-watering stack reliability and wastewater treatment plant were also being performed.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $2,648,825 compared to the original projection of $2,751,182 representing an insignificant variance.

Progress Summary: The project was placed in-service in January 2002.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is expected to be $2,590,639.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend PM Minimization and Monitoring

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment 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, as well as perform a best available control technology ("BACT") analysis for the upgrade of each existing ESP. The company is also required to install and operate particulate matter continuous emission monitors on 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:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $1,102,382 as compared to the original projection of $1,209,451 resulting in an insignificant variance.

The actual/estimated O&M expense the period January 2007 through December 2007 is $310,000 as compared to the original projection of $450,000 resulting in a variance of 31.1%. This variance is due to the decrease in inspection work during the Unit 4 outage as well as the overall improved precipitator performance.

Progress Summary: This project was placed in-service July 2005.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is expected to be $1,127,247.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $450,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend NO_x Emissions Reduction

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment 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 that 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:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $866,806 as compared to the original projection of $921,526 resulting in an insignificant variance.

The actual/estimated O&M expense the period January 2007 through December 2007 is $490,000 as compared to the original projection of $350,000 resulting in a variance of 40.0%. This variance is due to unanticipated inspections on boiler tubes and burner modifications.

Progress Summary: The project was placed in-service January 2007.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is expected to be $872,714.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $350,000.

Tampa Electric Company
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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, coating the internal floor plus 30 inches up the tank wall, installing an AEI 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:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $57,574 compared to the original projection of $57,574 representing no variance.

Progress Summary: The project was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $56,068.

Tampa Electric Company
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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, coating the internal floor plus 30 inches up the tank wall, installing an AEI 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:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $94,694 compared to the original projection of $94,694 representing no variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $92,212.

Tampa Electric Company
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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, coating the internal floor plus 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:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007, is $6,262 compared to the original projection of $6,430 representing an insignificant variance.

Progress Summary: The project is complete and was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $6,064.

Tampa Electric Company
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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, coating the internal floor plus 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:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $9,842 compared to the original projection of $10,103 representing an insignificant variance.

Progress Summary: The project is complete and was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $9,528.

Tampa Electric Company
Environmental Cost Recovery Clause
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Project Title: SO_2 Emission 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:

Fiscal Expenditures: The actual/estimated return on average net working capital for the period January 2007 through December 2007 is ($66,968) compared to the original projection of ($5,548) representing a 1107.1% variance. The variance is due to the sale of a portion of SO_2 allowances originally projected to occur in late 2006 but transpired throughout 2007.

The actual/estimated O&M for the period January 2007 through December 2007 is ($79,602,597) compared to the original projection of ($74,041,987) representing a variance of 7.5%. The significant variance is due to the sale of SO_2 allowances originally projected to occur in late 2006 that actually transpired in 2007.

Progress Summary: SO_2 emission allowances are being used by Tampa Electric to meet compliance standards for Phase I of the CAAA.

Project Projections: Estimated return on average net working capital for the period January 2008 through December 2008 is projected to be ($9,165).

Estimated O&M costs for the period January 2008 through December 2008 are projected to be ($29,413,430).

Tampa Electric Company
Environmental Cost Recovery Clause
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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:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2007 through December 2007 is $34,500 compared to the original projection of $34,500 representing no variance.

Progress Summary: NPDES Surveillance fees are paid annually for the prior year.

Projections: Estimated O&M costs for the period January 2008 through December 2008 are projected to be $34,500.

Tampa Electric Company
Environmental Cost Recovery Clause
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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.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2007 through December 2007 is $26,117 compared to the original projection of $10,000, which represents a variance of 161.2%. The variance is due to unusually wet conditions in 2005, which limited dry season sampling. For that reason, the dry season sampling was rescheduled for 2006 through 2007.

Progress Summary: This project was approved by the Commission in Docket No. 010593-EI on September 4, 2001. The project is expected to continue through at least 2008.

Projections: Estimated O&M costs for the period January 2008 through December 2008 are projected to be $50,000.

Tampa Electric Company
Environmental Cost Recovery Clause
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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, 2005. 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:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $214,062 as compared to the original projection of $212,592 representing an insignificant variance.

The actual/estimated O&M for the period January 2007 through December 2007 is $59,725 compared to the original projection of $57,000, which represents an insignificant variance.

Progress Summary: The project was placed in-service January 2005.

Project Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $207,879.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $65,000.

Tampa Electric Company
Environmental Cost Recovery Clause
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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:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2007 through December 2007 is $69,604 compared to the original projection of $76,000 resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. As an O&M project, expenses are ongoing annually.

Projections: Estimated O&M costs for the period January 2008 through December 2008 are projected to be $70,000.

Tampa Electric Company
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Project Title: Big Bend Unit 4 Separated Overfire Air ("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 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:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $339,520 compared to the original projection of $344,073 representing an insignificant variance.

The actual/estimated O&M for the period January 2007 through December 2007 is $220,000 compared to the original projection of $250,000, which represents a variance of 12.0%. This variance is due to less maintenance activity than anticipated.

Progress Summary: The project was placed in-service November 2004.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $332,096.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $50,000.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
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Project Title: Big Bend Unit 1 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2008 through 2010. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 1 Pre-SCR technologies include a neural network system, secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $283,636 compared to the original projection of $332,519 resulting in a variance of 14.7%. This variance is due to lower than anticipated windbox material costs and neural network tuning expenses, which will occur during the fall 2007 maintenance outage.

The actual/estimated O&M for the period January 2007 through December 2007 is $0 compared to the original projection of $75,000, which represents a variance of 100.0%. This variance is due to the delay of the in-service date for the capital project.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $279,624.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $75,000.

Tampa Electric Company
Environmental Cost Recovery Clause
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Project Title: Big Bend Unit 2 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2008 through 2010. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 2 Pre-SCR technologies include secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $228,630 compared to the original projection of $244,914 resulting in an insignificant variance.

The actual/estimated O&M for the period January 2007 through December 2007 is $15,000 compared to the original projection of $75,000, which represents a variance of 80.0%. This variance is due to the delay of the in-service date for the capital project.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $224,909.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $75,000.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
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Project Title: Big Bend Unit 3 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2008 through 2010. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 3 Pre-SCR technologies include a neutral network system, secondary air controls, windbox modifications and primary coal/air flow controls.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $133,737 compared to the original projection of $162,123 resulting in a variance of 17.5%. This variance is due to the deferment of activities and associated costs to 2008 after the completion of the outage scheduled for the end of 2007.

The actual/estimated O&M for the period January 2007 through December 2007 is $0 compared to the original projection of $0.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $437,512.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $0.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
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Project Title: Clean Water Act Section 316(b) Phase II Study

Project Description:

This project is a direct requirement from the EPA to reduce impingement and entrainment of aquatic organisms related to the withdrawal of waters for cooling purposes through cooling water intake structures. The Phase II Rule requires that power plants meeting certain criteria to comply with national performance standards for impingement and entrainment. Accordingly, Tampa Electric must develop its compliance strategies for its H. L. Culbreath Bayside Power and the Big Bend Power Stations and then submit these strategies for approval through a Comprehensive Demonstration Study to the FDEP.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M for the period January 2007 through December 2007 is $396,758 compared to the original projection of $736,192, which represents a variance of 46.1%. This variance is due to the sampling of the impingement survival study occurring at a slower rate than originally projected. The sampling activity is anticipated to resume the normal schedule on late 2007.

Progress Summary: This project was approved by the Commission in Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005.

Projections: Estimated O&M costs for the period January 2008 through December 2008 are projected to be $150,000.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
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Project Title: Big Bend Unit 1 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2008 through 2010. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 1 and is scheduled to go in-service May 2010.

Project Accomplishments:

Fiscal Expenditures: Based on the Commission's previous ruling in Docket No. 980693-EI, Tampa Electric will not seek ECRC recovery of capital costs for this project until May 2010, the expected in-service date for the project. At that time, the associated depreciation expense and allowance for funds used during construction will be requested for ECRC recovery.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $0.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $0.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
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Project Title: Big Bend Unit 2 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2008 through 2010. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 2 and is scheduled to go in-service May 2009.

Project Accomplishments:

Fiscal Expenditures: Based on the Commission's previous ruling in Docket No. 980693-EI, Tampa Electric will not seek ECRC recovery of capital costs for this project until May 2009, the expected in-service date for the project. At that time, the associated depreciation expense and allowance for funds used during construction will be requested for ECRC recovery.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $0.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $0.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
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Project Title: Big Bend Unit 3 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2008 through 2010. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 3 and is scheduled to go in-service May 2008.

Project Accomplishments:

Fiscal Expenditures: Based on the Commission's previous ruling in Docket No. 980693-EI, Tampa Electric will not seek ECRC recovery of capital costs for this project until April 2008, the expected in-service date for the project. At that time, the associated depreciation expense and allowance for funds used during construction will be requested for ECRC recovery.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $8,778,536.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $1,606,900.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
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Project Title: Big Bend Unit 4 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2008 through 2010. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 4 and is scheduled to go in-service June 2008.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $5,145,048 compared to the original projection of $5,630,498, which represents an insignificant variance.

The actual/estimated O&M for the period January 2007 through December 2007 is $759,873 compared to the original projection of $1,256,000 representing a variance of 39.5%. The significant variance is due to less flyash mitigation costs compared to the original projection as well as the decreased usage of ammonia.

Progress Summary: This project went in to service in May 2007.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $6,125,701.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $1,610,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
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Project Title: Arsenic Groundwater Standard Program

Project Description:
The Arsenic Groundwater Standard Program that is required by the Environmental Protection Agency and the Department of Environmental Protection became effective January 1, 2005. It requires regulated entities of the State of Florida to monitor the drinking water and groundwater Maximum Contaminant Level ("MCL") for arsenic under the federal rule known as the Safe Drinking Water Act.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M for the period January 2007 through December 2007 is $52,500 compared to the original projection of $105,000, which represents a variance of 50.0%.The project is on hold pending comments from the FDEP.

Progress Summary: In Docket No. 050683-EI, Order No. PSC-06-0138-PAA-EI, issued February 23, 2007, the Commission granted Tampa Electric cost recovery approval for prudent costs associated with this project.

Projections: Estimated O&M costs for the period January 2008 through December 2008 are projected to be $57,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2008 through December 2008
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Flue Gas Desulfurization ("FGD") System Reliability

Project Description:
The Big Bend FGD Reliability project is necessary to maintain the FGD system operations that are required by the Consent Decree. Tampa Electric is required to operate the FGD systems at Big Bend Station whenever coal is combusted in the units with few exceptions. The compliance dates for the strictest operational characteristics are January 1, 2010 for Big Bend Unit 3 and January 1, 2013 for Big Bend Units 1 and 2.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $778,808 compared to the original projection of $906,108, which represents a variance of 14.0%. The variance is due to the scheduled delivery of materials in 2007 that were actually received in late 2006.

Progress Summary: In Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2007, the Commission granted cost recovery approval for prudent costs associated with this project.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $1,549,199.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
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Project Title: Clean Air Mercury Rule ("CAMR")

Project Description:
The EPA established standards of performance for mercury for new and existing coal-fired electric utility steam generating units as defined in the federal CAA Section 111, effective January 2009. CAMR will permanently cap and reduce mercury emissions nation-wide in two phases: Phase I cap is 38 tons per year with a compliance date of 2010 and Phase II cap is 15 tons per year with a compliance date of 2018. Tampa Electric's Big Bend and Polk Power Stations will be affected by the nation-wide mercury emissions reduction rule. According to Rule, the company must install emission-monitoring systems that sample mercury found in flue gas on Big Bend Units 1 through 4 and Polk Unit 1.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2007 through December 2007 is $0 compared to the original projection of $30,226, which represents a variance of 100.0%. The project is on hold pending comments from FDEP before the study can resume.

Progress Summary: A petition was filed on August 30, 2007 seeking Commission approval of cost recovery through the ECRC for the new CAMR program.

Projections: Estimated depreciation plus return for the period January 2008 through December 2008 is projected to be $119,317.

Estimated O&M costs for the period January 2008 through December 2008 are projected to be $0.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2008 to December 2008

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	56.60%	9,337,418,924	1,883,243	1.0658538	1.0488279	9,793,345,481	2,007,262	46.06%	53.74%	53.15%
GS, GST, TS	59.28%	1,104,962,002	212,782	1.0658538	1.0488279	1,158,914,976	226,795	5.45%	6.07%	6.02%
GSD, GSDT	71.68%	5,673,156,965	903,489	1.0651761	1.0482194	5,946,713,190	962,375	27.97%	25.76%	25.93%
GSLD, GSLDT, SBF	84.31%	2,580,295,464	349,371	1.0514324	1.0372458	2,676,400,633	367,340	12.59%	9.83%	10.04%
IS1, IST1, SBI1, SBIT1, IS3, IST3, SBI3	99.56%	1,434,557,515	164,486	1.0223035	1.0175028	1,459,666,288	168,155	6.86%	4.50%	4.68%
SL/OL	770.77%	216,845,654	3,212	1.0658538	1.0488279	227,433,772	3,424	1.07%	0.09%	0.17%
TOTAL *		20,347,236,524	3,516,583			21,262,474,340	3,735,351	100.00%	100.00%	100.00%

Notes: (1) Average 12 CP load factor based on actual 2004 load research data
(2) Projected kWh sales for the period January 2008 to December 2008
(3) Calculated: (Column 2) / (8,760 hours x Column 1)
(4) Based on actual 2004 load research data
(5) Based on actual 2004 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
* Totals on this schedule may not foot due to rounding

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DOCUMENT NO. 6

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2008 to December 2008

Rate Class	(1) Percentage of kWh Sales at Generation (%)	(2) 12 CP & 1/13 Allocation Factor (%)	(3) Energy-Related Costs ($)	(4) Demand-Related Costs ($)	(5) Total Environmental Costs ($)	(6) Projected Sales at Meter (kWh)	(7) **Environmental Cost Recovery Factors (¢/kWh)**
RS, RST	46.06%	53.15%	9,847,189	(96,223)	9,750,966	9,337,418,924	**0.104**
GS, GST, TS	5.45%	6.02%	1,165,158	(10,899)	1,154,259	1,104,962,002	**0.104**
GSD, GSDT	27.97%	25.93%	5,979,719	(46,944)	5,932,775	5,673,156,965	**0.105**
GSLD, GSLDT, SBF	12.59%	10.04%	2,691,622	(18,177)	2,673,445	2,580,295,464	**0.104**
IS1, IST1, SBI1, SBIT1, IS3, IST3, SBI3	6.86%	4.68%	1,466,603	(8,473)	1,458,130	1,434,557,515	**0.102**
SL/OL	1.07%	0.17%	228,756	(308)	228,448	216,845,654	**0.105**
TOTAL *	100.00%	100.00%	21,379,046	(181,041)	21,198,005	20,347,236,524	**0.104**

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
* Totals on this schedule may not foot due to rounding

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DOCUMENT NO. 7